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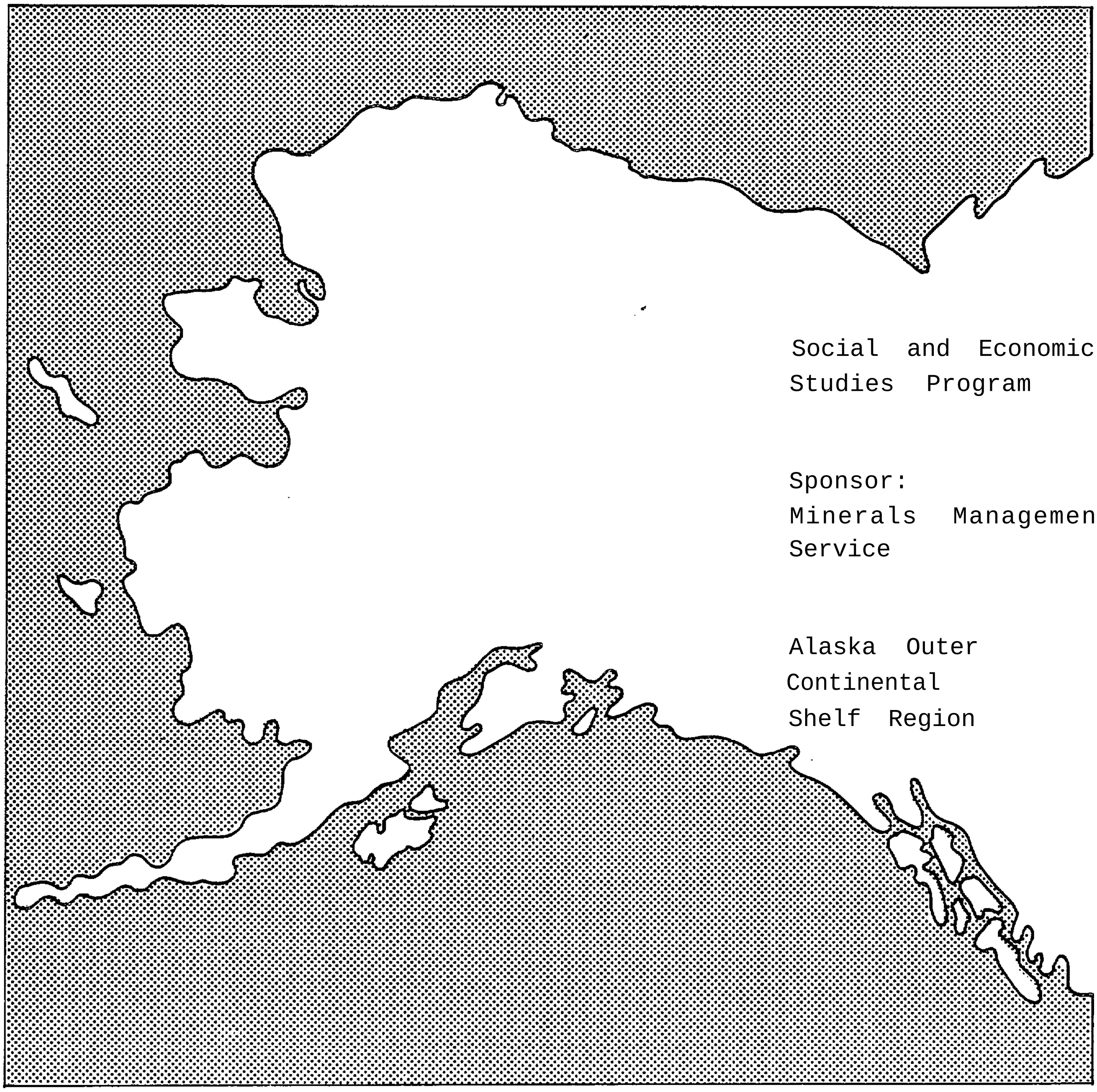
OCS Study MMS 84-0027

U.S. Department of the Interior

Technical Report Number 110 Volume I



Social and Economic Studies Program

Sponsor:
Minerals Management Service

Alaska Outer Continental Shelf Region

Evaluation Of Bering Sea Crude Oil Transportation Systems

TECHNICAL REPORT NO. 110

CONTRACT NO. 14-12-0001-30077

EVALUATION OF BERING SEA
CRUDE OIL TRANSPORTATION SYSTEMS

Prepared For:

MINERALS MANAGEMENT SERVICE

ALASKA OUTER CONTINENTAL SHELF REGION

LEASING AND ENVIRONMENT OFFICE

SOCIAL AND ECONOMIC STUDIES UNIT

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NEW YORK, NEW YORK

JULY 1984

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NOTICE

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ABSTRACT

The objective of this study is to evaluate and compare the technology and costs associated with crude oil transportation alternatives from the Bering Sea. In order to achieve this objective, three representative scenarios were developed. All relevant scenario parameters were defined and the potential range of critical parameter values was established for sensitivity analysis purposes. The environmental parameters are based on information in the public domain and the forces exerted on the various types of offshore structures were determined based on state-of-the-art procedures. Details were developed for each major element of the transportation system, including, offshore loading system, offshore storage system, nearshore loading system, onshore storage facilities, transshipment terminal, marine pipeline, land pipeline, ice-strengthened tankers, conventional tankers, and icebreakers. These elements were combined to make up all reasonable transportation alternatives and total life cycle costs were developed. The alternatives were also compared on the basis of construction logistics, reliability, environmental considerations and other factors.

For the base case parameters of all three scenarios, the optimum crude oil transportation alternative consists of an offshore loading terminal for loading two ice-strengthened tankers traveling directly between the terminal and the U.S. West Coast. The offshore terminal for the Northern Bering Sea consists of a concrete crude oil storage

structure with a capacity of 1.5 MMB, a separate concrete mooring structure and interconnecting pipelines. The tankers are 169,000 DWT and are strengthened and powered for Class 4. Two Class 5 icebreaker support vessels are required. The offshore terminal for the Central Bering Sea consists of a combined storage/loading facility and pipeline connecting it with the production platform. The storage/loading facility consists of a floating storage vessel with a capacity of 1.7 MMB, permanently moored to a catenary chain stabilized articulated column. The 160,000 DWT tankers are strengthened and powered for Class 2 and moor. in tandem to the storage vessel. Two Class 3 icebreaker support vessels are required. The offshore terminal for the Southern Bering Sea is similar to that for the Central Bering Sea except that the storage vessel has a capacity of 1.3 MMB and the articulated column does not require catenary chains. The tankers are 137,000 DWT and are strengthened and powered for Class 1. Two Class 2 icebreaker support vessels are required.

The sensitivity evaluation indicates that the average crude oil transportation cost (ATC) is quite sensitive to the quantity of total recoverable reserves for reserves less than approximately one billion barrels. All other sensitivity factors, except crude oil properties, do not have a significant effect on the ATC although they may affect the cost of a particular transportation system element. The base case crude oil is quite suitable for either tanker or pipeline transportation but it would be impractical to transport crude oil with the sensitivity case properties through a long marine pipeline.

1.0 INTRODUCTION

1.1 OBJECTIVE

The objective of this study is to evaluate and compare the technology and costs associated with crude oil transportation alternatives from the Bering Sea Lease Sale areas. There are a great number of possible transportation alternatives and they are generally categorized as either offshore loading systems or pipeline systems. However, all the alternatives contain the following basic transportation elements in some form:

- pipelines,
- crude oil storage system,
- tanker loading system, and
- tankers.

The specific objectives of this study are:

- to identify and evaluate the technology for loading crude oil tankers given the severe environmental constraints of the Bering Sea,
- to identify and evaluate the technology for transporting crude oil by marine or land pipeline, and
- to evaluate and compare the various transportation alternatives, illustrating the advantages and disadvantages of each system and analyzing the key variables which most contribute to the outcome of the comparison.

1.2 SCOPE

The area considered in this study includes the four lease sale areas within the Bering Sea: Norton Basin, Navarin Basin, St. George Basin and North Aleutian Basin. These areas are shown on Figure 1-1. The Norton Basin is bounded on the north by 65° north latitude, on the south by 63° north latitude, on the east by the Alaskan main and and on the west by the U.S. - Russia Convention Line of 1867. The Navarin Basin is bounded on the north by 63° north latitude, on the south by 58° north latitude, on the east by 174° west longitude, on the southwest by the 2,400 meter (7,900 foot) isobath, and on the west by the U.S. - Russia Convention Line of 1867. The St. George Basin is bounded on the north by 59° north latitude, on the southeast by the Aleutian Islands, on the southwest by 56° north latitude, on the east by 165° west longitude, on the west (northern portion) by 174° west longitude, and on the west southern portion) by 171° west longitude. The North Aleutian Basin is bound on the north by 59° north latitude, on the west by 165° west longitude and on the south and east by the Alaska Peninsula and the Alaskan mainland.

The scope of this study includes the evaluation of all reasonable crude oil transportation systems from the study area. Crude oil transportation only is considered and natural gas is specifically excluded. The emphasis of the information gathering has been on technologies and environmental constraints as they affect the capital and operating costs of offshore tanker loading. Since no

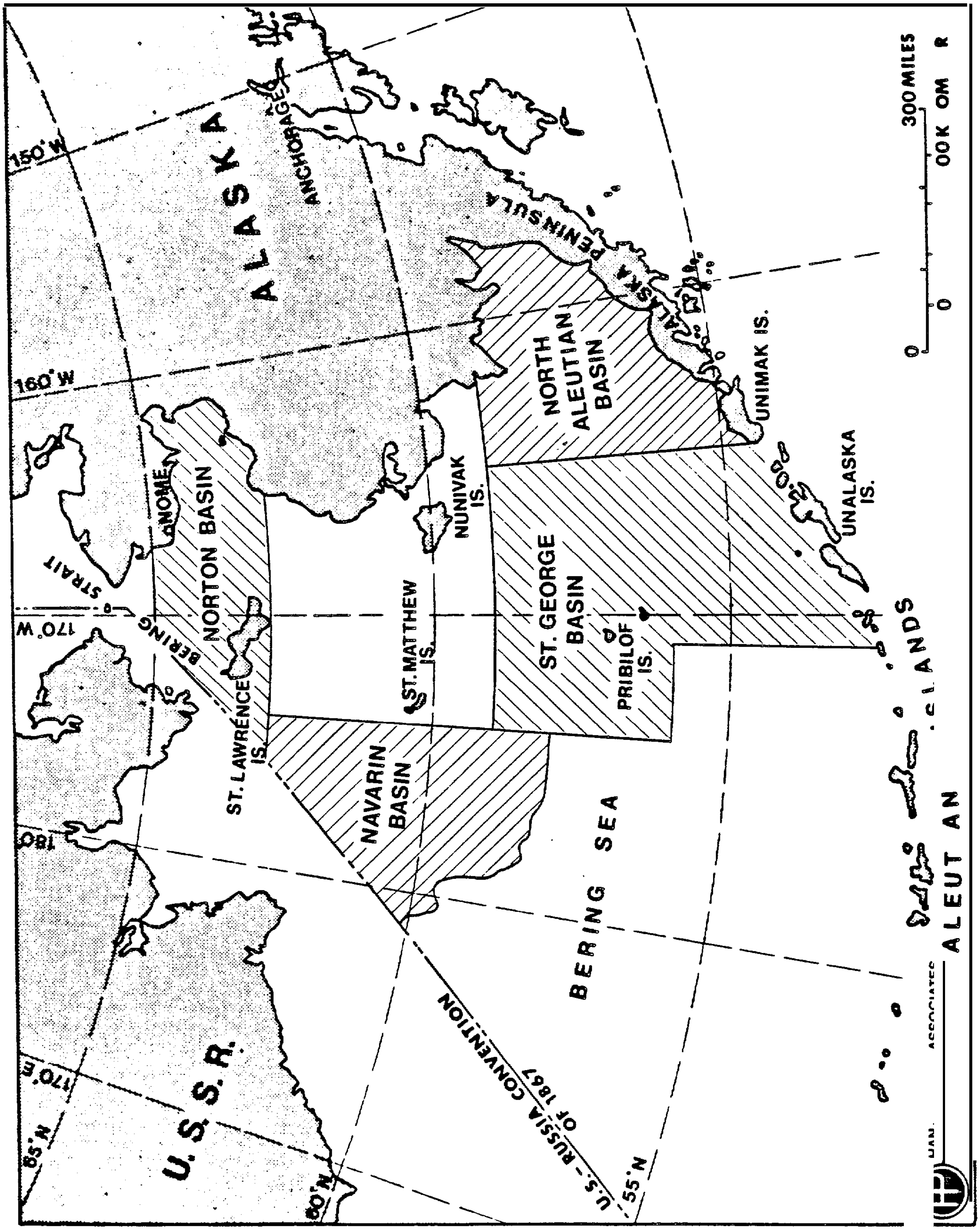

Figure 1-1. Lease sale areas of the Bering Sea.

existing offshore tanker loading operations take place in conditions similar to those that exist in the Bering Sea during the winter, considerable conceptual development of suitable offshore loading systems has been carried out.

Extensive documentation of petroleum 'industry experience in the North Sea as it applies to crude oil transportation has been gathered to provide a basis for evaluation of Bering Sea transportation alternatives. This documentation is contained in Appendix A of this report. Approximately ten years of operating experience in the North Sea is available and this experience can provide valuable insight and a realistic basis for evaluating potential offshore loading systems and pipeline systems in the Bering Sea. However, it is extremely important to bear in mind that North Sea experience is not directly applicable to the Bering Sea because a number of major factors affecting oil field development are quite different.

1.3 PROCEDURE

In order to carry out technological and cost analyses of systems for transporting crude oil from the Bering Sea, a number of assumptions must be made and parameters established. Obviously, the optimum crude oil transportation system for a particular offshore oil field development scenario depends on the characteristics and details of that scenario. Therefore, three basic scenarios have been defined and form the basis on which the technological and cost analyses have been developed. One of the scenarios is representative of the northern portion of the Bering Sea, one representative of the central portion, and one representative of the southern portion. These three locations were selected because the extent of ice cover and size of ice features varies considerably from the northern to southern edges of the Bering Sea and it is the presence of ice that creates the most significant difference between the Bering Sea environment and the environments in which previous offshore oil field development have taken place. The three representative locations are indicated on Figure 1-2. The locations selected appear to be approximately the center of the high interest tracts of the basin involved and are representative of the range of environmental conditions that will be encountered in the Bering Sea lease sale areas. Sensitivity analyses were carried out for a range of locations surrounding each representative location.

All relevant parameters for each scenario were defined including, environmental factors, crude oil production parameters and crude oil destinations. After establishing base case values for each of the parameters for each scenario, the potential range of critical parameters was established and the sensitivity of the analyses to each critical parameter was evaluated and quantified. While the three scenarios are not comprehensive regarding complete exploration, development and production operations, they are of sufficient detail to permit a meaningful comparison of alternatives.

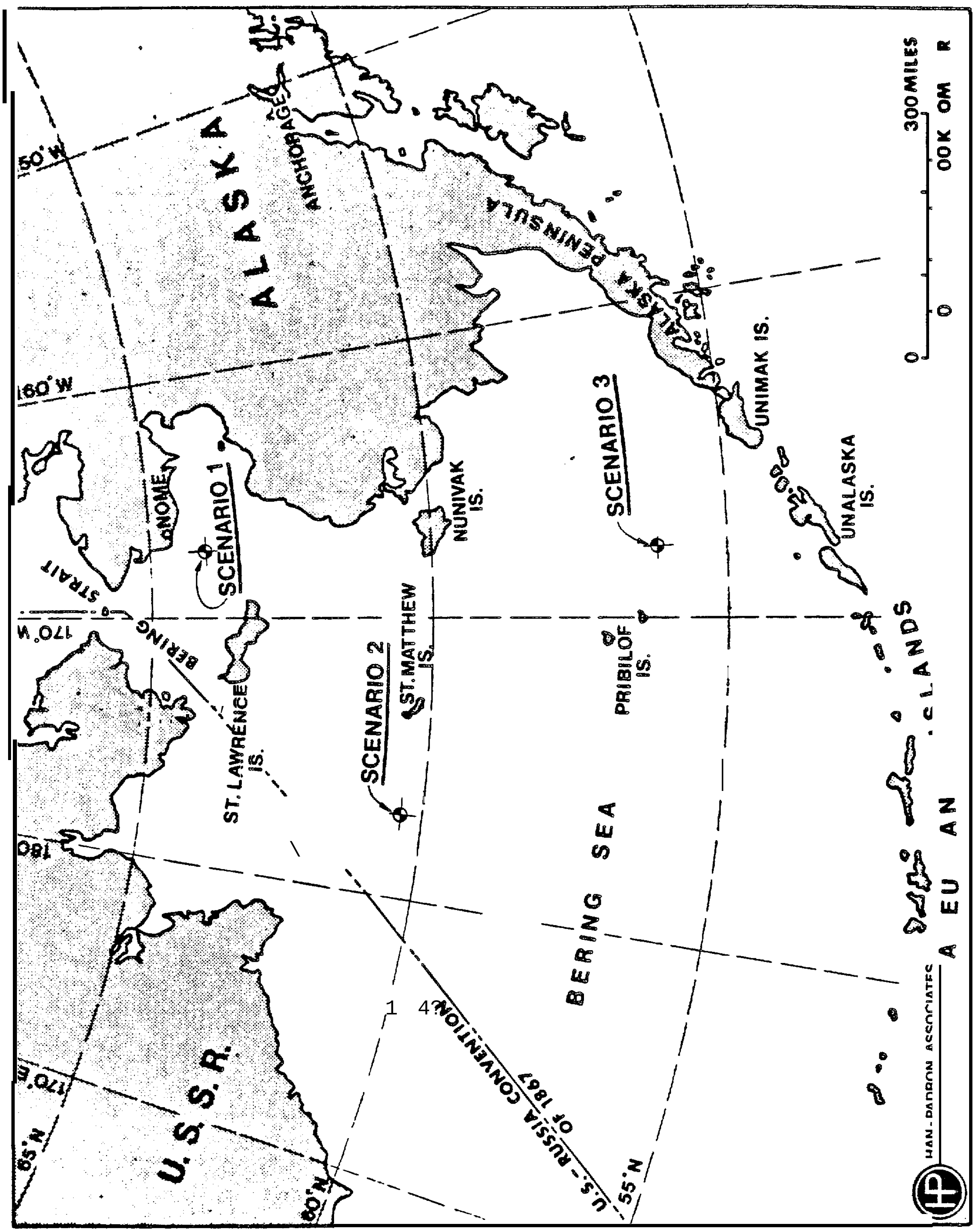

Figure 1-2. Locations of selected scenarios.

The various alternatives were evaluated on the basis of technical feasibility, capital costs, operating costs, timing and sensitivity to the crude oil production scenario parameters. The present values of total life cycle costs for each transportation alternative were developed for comparison purposes. All costs presented in this report are based on constant, January 1982 U.S. dollars, unless specifically indicated otherwise, and do not account for future inflation. All present value calculations were based on an 8 percent rate of return and the effect of taxes and royalties were not considered. No allowance has been made for delays and consequent cost escalation that may result from permit and regulatory difficulties. Construction costs were considered to be expended uniformly over the construction period of each facility. It was assumed that crude oil production would cease after 15 years, at which time the production rate would have decreased to approximately 25 percent of the peak production rate. A salvage value equal to the scrap value was assigned to vessels and all other facilities were assumed to have no salvage value.

Each scenario has been analyzed separately assuming no linking with development elsewhere. Thus, it has been assumed that there wll be no sharing of costs of any of the transportation elements (pipelines, tankers, transshipment terminals, support bases, etc.) among the scenarios. Also, it has been assumed that offshore storage and loading systems are independent of drilling/production platforms.

Actually, it is highly likely that. offshore crude oil storage facilities would be contained within the drilling/production platform, thus reducing the total cost of the combined system.

When comparing crude oil transportation system alternatives, the total system, from the production platform to the refinery, must be included in order for the analysis to be meaningful. For each scenario considered, it has been assumed that the ultimate destination of the crude oil will be a U.S. West Coast port. In order to calculate distances and transit times, San Francisco has been selected as the receiving terminal site. However, the selection of any other West Coast site between Seattle and San Diego would not affect the conclusions of this study. Distances from each scenario offshore loading system to San Francisco are shown on Figure 1-3. A requirement to deliver the Bering Sea crude oil to a U.S. Gulf Coast or East Coast site may affect the study conclusions. However, since the likelihood of such a long route is remote, it has not been considered in this study.

The analyses carried out were based upon environmental data available in the public domain. There are additional environmental data existent but they are proprietary and not available for this study. While the available data are quite extensive and are adequate for preliminary general evaluation of alternative crude oil transportation systems, they are not sufficient to provide a sound basis for the final selection of the optimum transportation system

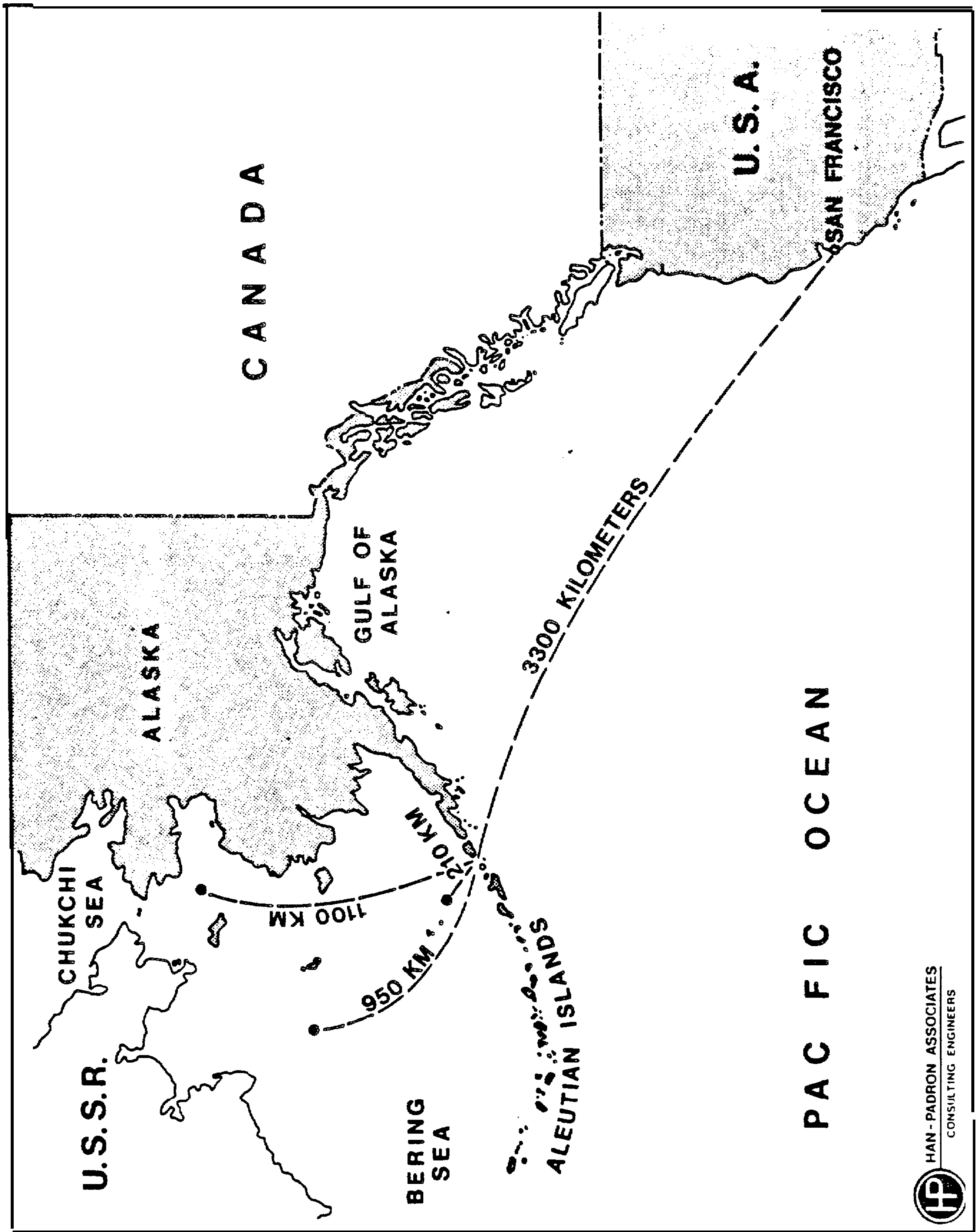

Figure 1-3. Tanker routes and distances.

for a particular situation. The cost of many of the transportation system elements is quite sensitive to specific site conditions and such conditions must be fully defined before a final analysis can be performed.

1.4 REPORT CONTENT AND FORMAT

This report has been organized, starting with Chapter 3, in the sequence in which an engineering evaluation to determine the optimum crude oil transportation system for a particular scenario would be carried out.

Chapter 2 presents the conclusions reached regarding the optimum transportation system for each of the Bering Sea regions.

Chapter 3 describes the approach, assumptions and reasoning used in evaluating each of the transportation system elements and establishing the environmental and other design criteria on which the preliminary design of each element is based. Section 3.1 describes the methodology used to establish design values for each of the environmental criteria and Section 3.2 describes the procedures used to calculate all the environmental forces acting on each of the offshore facilities. Section 3.3 defines the characteristics of the crude oil to be produced, the quantity recoverable, the initial productivity and the optimum rate of recovery used for this study. Section 3.4 describes the methodology used for selecting to optimum size of ice-strengthened and conventional tankers and icebreaker support vessels and the basis on which the capital and operating cost of the tankers and icebreakers was established. Section 3.5 describes the philosophy utilized in selecting the type of facilities to be provided for offshore, nearshore and transshipment terminals. It also describes the limiting environmental conditions during which each of the terminals can operate, the methodology used for determining the number of tanker mooring berths to be provided. and the methodology used for determining the amount of crude oil storage capacity to be provided at each type of terminal. The philosophy used to develop preliminary designs and costs for the marine pipelines and land pipelines are described in Sections 3.6 and 3.7, respectively.

Chapters 4, 5 and 6 contain the overall analyses of the technology and costs of the transportation system alternatives for the Northern Bering Sea, Central Bering Sea and Southern Bering Sea, respectively. The sequence of the sections within each chapter is similar to the sequence of Chapter 3, presenting the development of each element of each transportation system in the order in which it is evaluated in the overall analysis. Each of the three chapters has been prepared to stand apart from the other two so that, along with Chapter 3, it presents the complete results of the analyses of its scenario. This results in some repetition among the three chapters but was deemed preferable for overall ease of use of the report.

All references are fully documented in Chapter 7.

Appendix A contains documentation of petroleum industry operating experience in the North Sea. Twenty-six active oil fields were selected for analysis, eight of which presently utilize an offshore loading system as the long term method for transporting crude oil.

Appendix B contains tables listing results of all the sensitivity analyses for each scenario and for each transportation alternative.

2.0 CONCLUSIONS

The analyses of transportation systems for shipping crude oil from the Bering Sea to the U.S. West Coast carried out for this study have been based on clearly defined sets of parameters for scenarios representative of the northern, central and southern portions of the Bering Sea. Critical parameters have been varied within an established range to evaluate the sensitivity of the results. The conclusions described below will require re-evaluation if:

- two or more major oil discoveries in the Bering Sea are developed simultaneously and can share a transportation system,
- the scenario parameters of a particular discovery vary significantly from the parameters defined herein, or
- commercial quantities of gas are discovered along with a crude oil discovery.

Within the above limitations, the conclusions reached for the base case parameters of each scenario are described in the following sections.

2.1 SCENARIO 1 - NORTHERN BERING SEA

The optimum crude oil transportation system from the Northern Bering Sea consists of an offshore loading terminal for loading ice-strengthened tankers shuttling directly between the terminal and the

U.S. West Coast. The offshore terminal consists of a crude oil storage structure, a separate tanker loading structure and interconnetting pipelines, as illustrated schematically in Figure 2-1.

The offshore loading system, illustrated in Figure 2-2, is a rigid, gravity stabilized, cylindrical tower, with a conical surface at the waterline and a large base for stability. A large rotating boom is fitted on top of the structure for mooring of the tanker and to support the crude oil loading system. It also contains living quarters and support facilities for the operating/maintenance crew and a helideck. The concrete structure would be prefabricated off-site, complete with the boom, towed to location approximately 1.6 km (1 mi) from the storage structure, lowered to the seabed and ballasted sufficiently to resist ice and wave forces.

The storage structure, illustrated in Figure 2-3, is a large, essentially cylindrical, concrete structure that would be prefabricated off-site, towed to location near the drilling/production platform(s) and ballasted to rest on the seabed. It has a storage capacity of 1.5 million barrels and is completely self-contained, with living quarters for operation/maintenance crew, power plant, utilities, pumping/metering for tanker loading, etc. A seawater displacement system is utilized for discharging crude oil from the storage compartments and a ballast water treatment system is provided to treat the seawater discharged as crude is pumped into the storage structure.

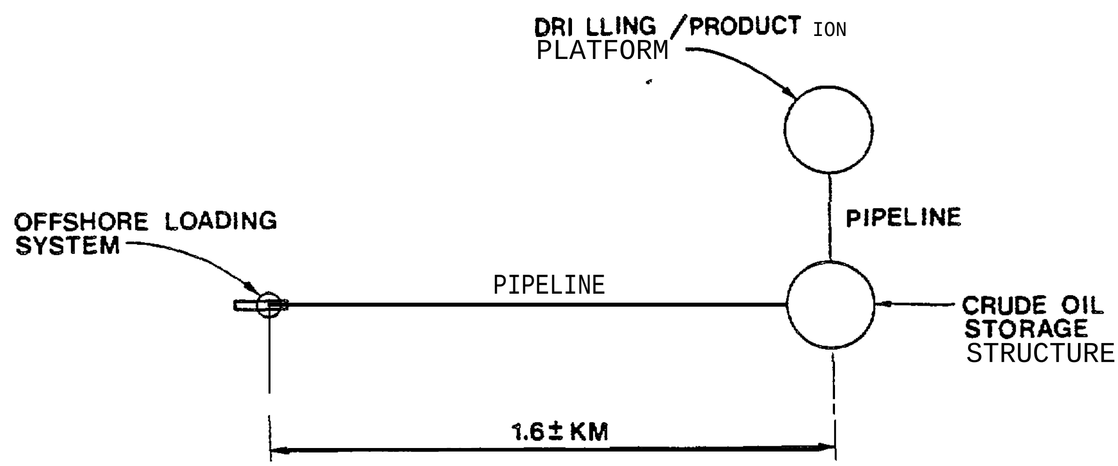

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Figure 2-1. Scenario 1 schematic layout of offshore loading terminal.

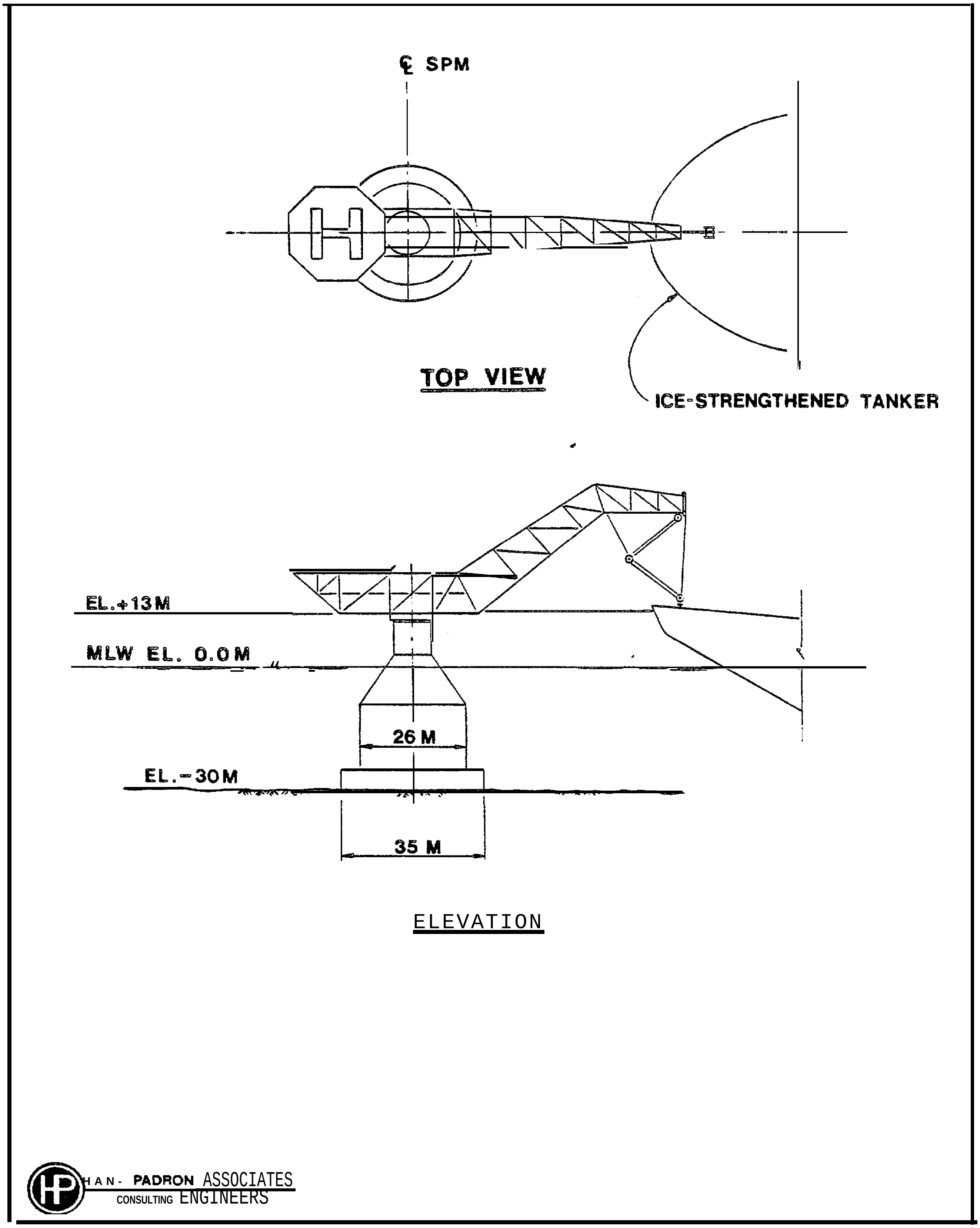

Figure 2-2. Scenario 1 offshore loading system.

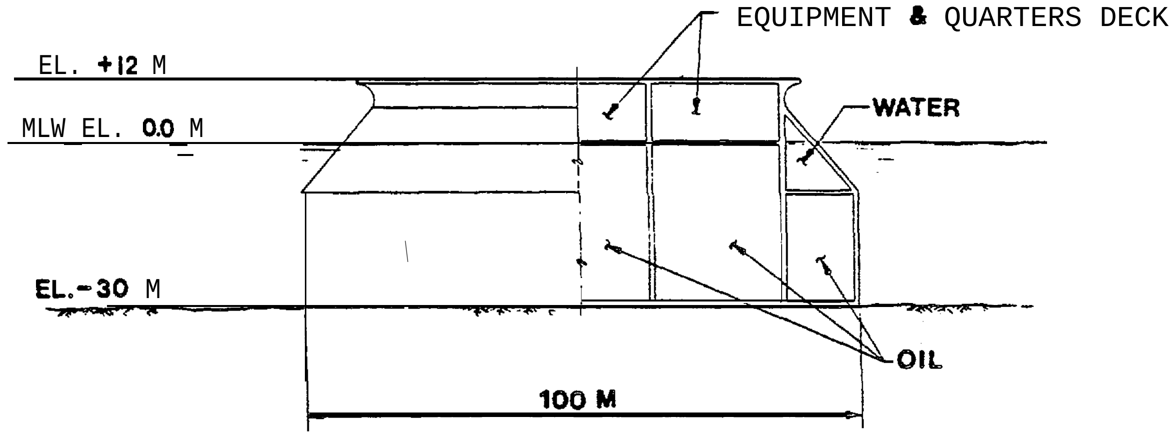

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Figure 2-3. Scenario 1 offshore storage structure.

Two 169,000 DWT tankers, strengthened and powered for Class 4, shuttle between the offshore loading terminal and the U.S. West Coast. Two Class 5 icebreakers are provided to assist in tanker maneuvering and mooring operations and to provide the general operating supply and maintenance requirements of the terminal.

2.2 SCE?WR1O 2 - CENTRAL BERING SEA

The optimum crude oil transportation system from the Central Bering Sea consists of an offshore loading terminal for loading ice-strengthened tankers shuttling directly between the terminal and the U.S. West Coast. The offshore terminal consists of a combined storage/loading system, located approximately 1.6 km (1 mi) from the production platform, and a pipeline connecting it with the production platform, as illustrated schematically in Figure 2-4.

The storage/loading facility, illustrated in Figure 2-5, consists of a floating storage vessel with a capacity of 1.7 million barrels, permanently moored by means of a rigid yoke to a catenary chain stabilized articulated column. The storage vessel is a purpose built vessel, similar to an ice-strengthened tanker but with a better ice breaking configuration. It has a segregated ballast system to enable it to maintain a virtually constant draft and is equipped with living quarters for operation/maintenance crew, power plant, utilities, pumping/metering for tanker loading, etc. The stern of

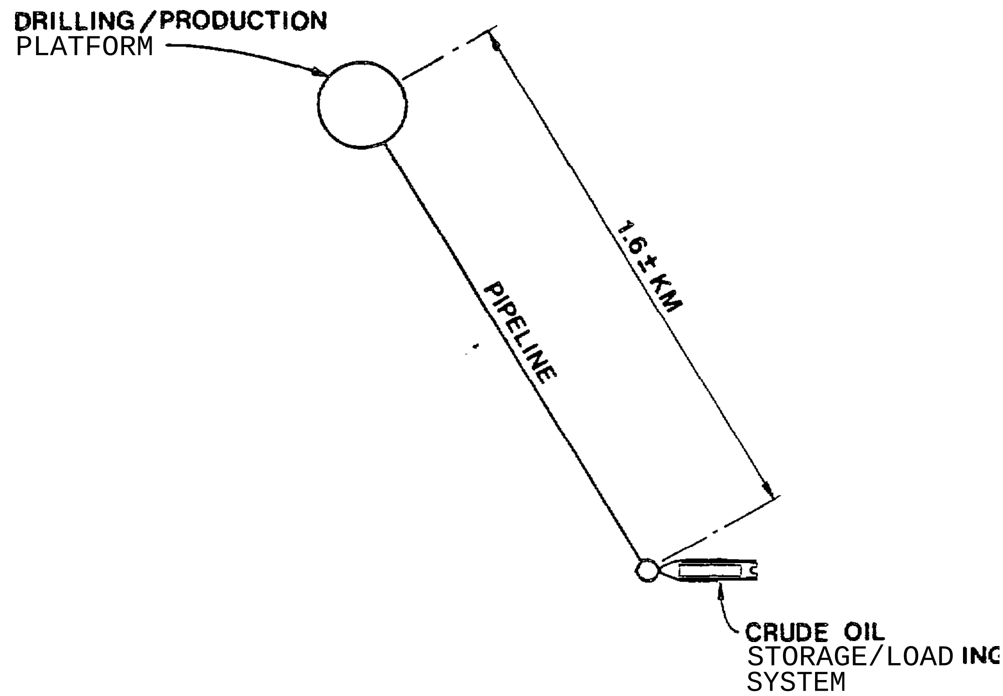

Figure 2-4. Scenarios 2 & 3 schematic layout of offshore loading terminal.

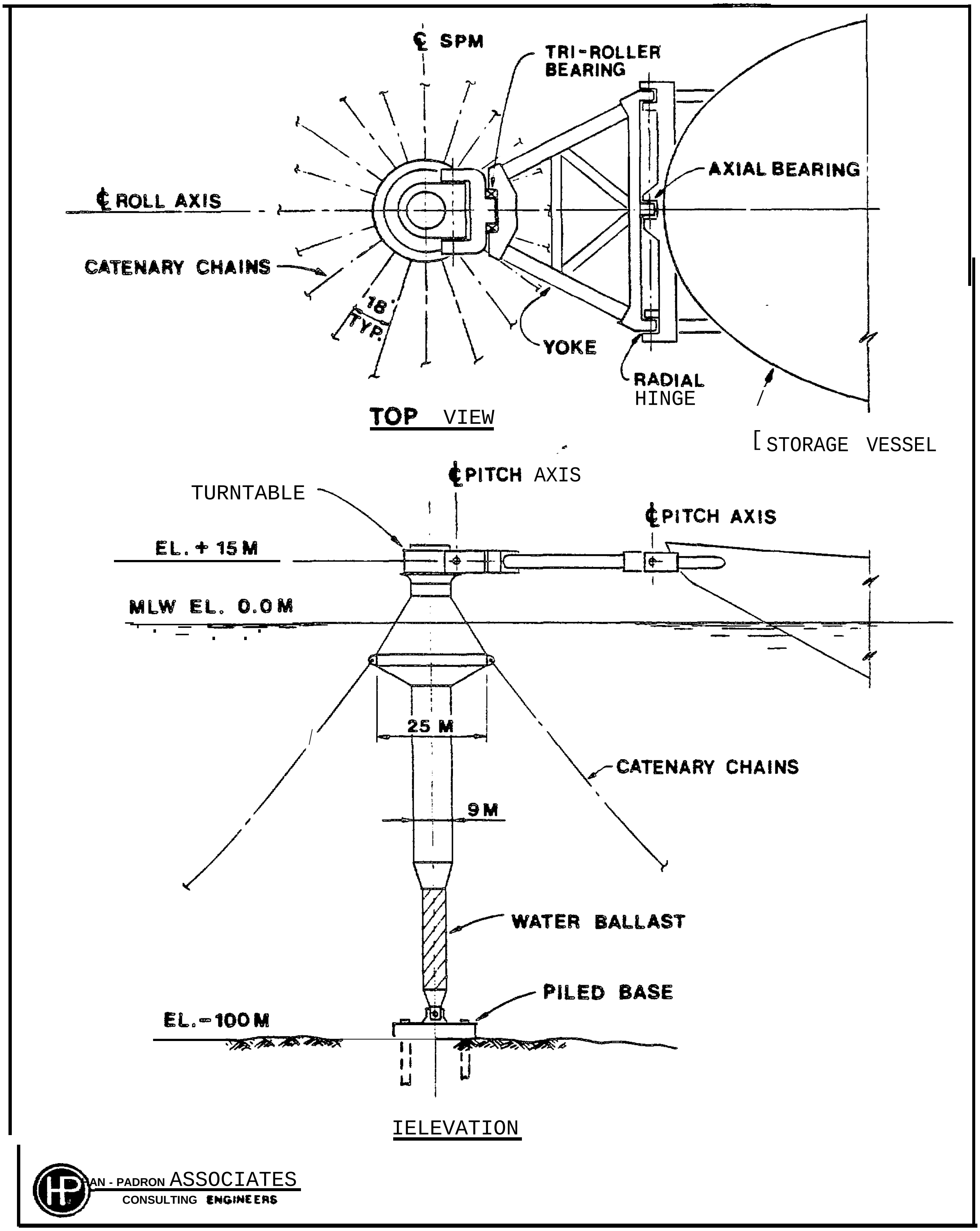

Figure 2--5. Scenario 2 offshore storage/loading system.

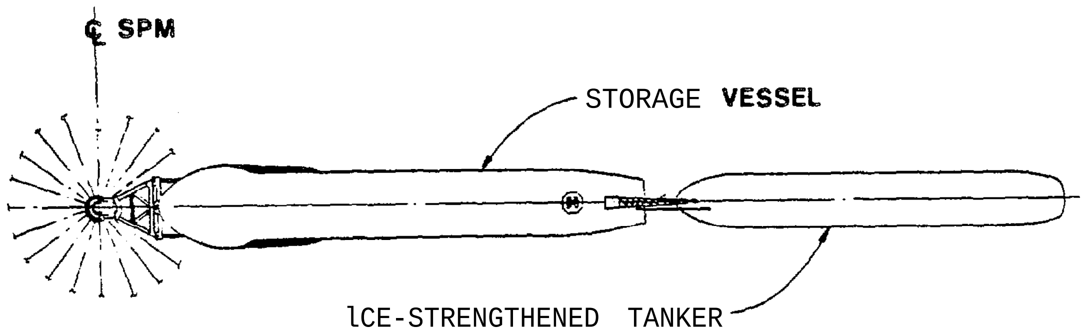

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Figure 2-6. Scenario 2 offshore storage/loading system tandem mooring configuration.

the vessel is equipped with a long boom to pass the mooring lines and support the crude oil loading system for the shuttle tanker to moor in tandem, as illustrated in Figure 2-6.

The articulated column is a relatively small diameter rigid steel cylinder, connected to a foundation structure by means of a universal joint, and fitted with an icebreaking cone at the waterline. Catenary chains connected to the perimeter of the cone and anchored to the seabed by piles provide the stabilizing force for the tower. The top of the tower has a turntable and an articulated yoke connected to the bow of the storage vessel.

Two 160,000 DWT tankers, strengthened and powered for Class 2, shuttle between the offshore loading terminal and the U.S. West Coast. Two Class 3 icebreakers are provided to assist in tanker maneuvering and mooring operations and to provide the general operation, supply and maintenance requirements of the terminal.

2.3 SCENARIO 3 - SOUTHERN BERING SEA

The optimum crude oil transportation system from the Southern Bering Sea consists of an offshore loading terminal for loading ice-strengthened tankers shuttling directly between the terminal and the U.S. West Coast. The offshore terminal consists of a combined storage/loading system, located approximately 1.6 km (1 mi) from the production platform, and a pipeline connecting it with the production platform, as illustrated schematically in Figure 2-4.

The storage/loading facility, illustrated in Figure 2-7, consists of a floating storage vessel with a capacity of 1.3 million barrels, permanently moored by means of a rigid yoke to a buoyancy stabilized articulated column. The storage vessel is a purpose built vessel, similar to an ice-strengthened tanker but with a better ice breaking configuration. It has a segregated ballast system to enable it to maintain a virtually constant draft and is equipped with living quarters for operation/maintenance crew, power plant, utilities, pumping/metering for tanker loading, etc. The stern of the vessel is equipped with a long boom to pass the mooring lines and support the crude oil loading system for the shuttle tanker to moor in tandem, as illustrated in Figure 2-8.

The articulated column is a relatively small diameter rigid steel cylinder, connected to a foundation structure by means of a universal joint, and fitted with an icebreaking cone at the waterline. The tower has a large buoyancy tank near the top to provide the stabilizing force for the tower. The top of the tower has a turntable and an articulated yoke connected to the bow of the storage vessel.

Two 137,000 DWT tankers, strengthened and powered for Class 1, shuttle between the offshore loading terminal and the U.S. West Coast. Two Class 2 icebreakers are provided to assist in tanker

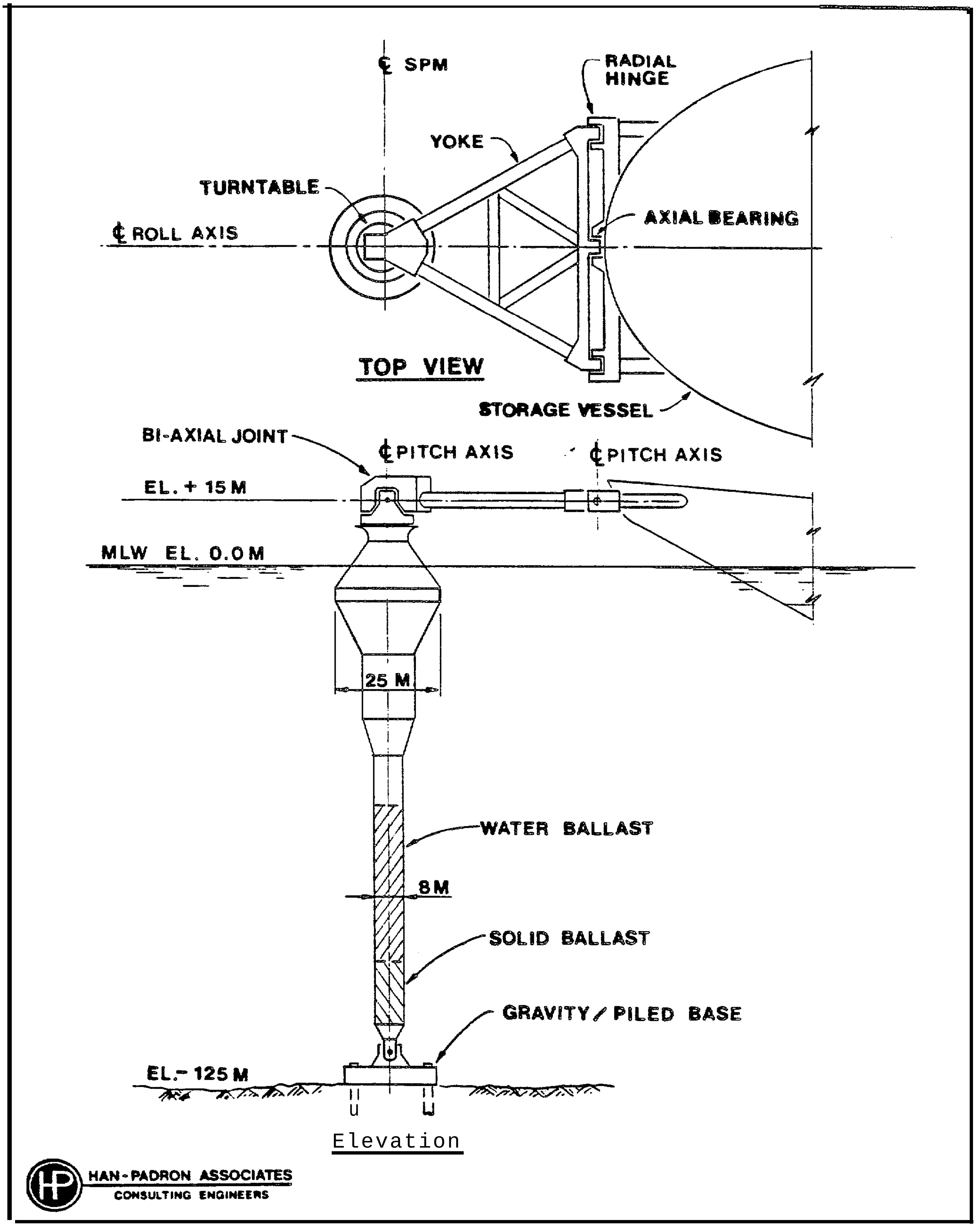

Figure 2-7. Scenario 3 offshore storage/loading system.

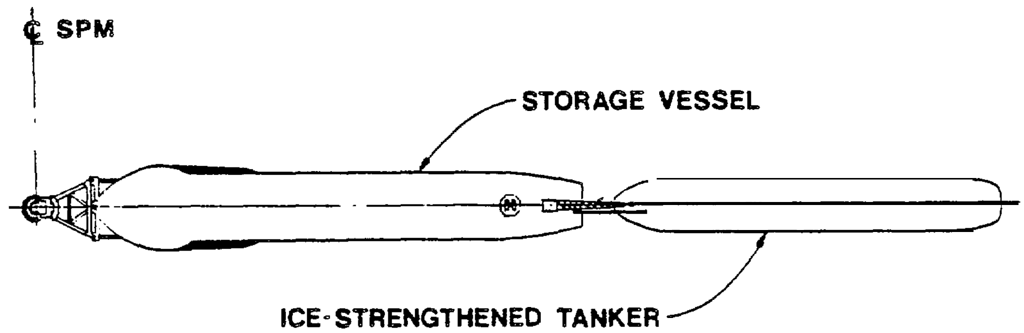

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Figure 2-8. Scenario 3 offshore storage/loading system tandem mooring configuration.

maneuvering and mooring operations and to provide the general operation, supply and maintenance requirements of the terminal,

3.0 METHODOLOGY

This chapter contains a description of the methodology used in evaluating the various Bering Sea crude oil transportation alternatives. The approach, assumptions and reasoning used in evaluating each element of the transportation system are defined. Elements that are common to all scenarios evaluated, or that vary only slightly for the different scenarios, are fully defined in this chapter. Elements that are significantly different for each scenario are defined only in general terms and are fully defined in Chapters 4, 5 and 6 for Scenarios 1, 2 and 3, respectively. The contents of Chapter 3 are presented in the following sequence:

- environmental design criteria,
- determination of environmental forces,
- definition of crude oil parameters,
- development of tanker and icebreaker data.
- development of tanker terminal data for offshore, nearshore and transshipment terminals,
- development of marine pipeline data, and
- development of land pipeline data.

3.1 DETERMINATION OF ENVIRONMENTAL DESIGN CRITERIA

The environment in which an offshore loading system or pipeline system must be installed and function will obviously have a great effect on both construction and operating costs. No offshore oil field development has as yet taken place in an environment similar to that of the Bering Sea. The North Sea environment, where approximately ten years of petroleum development and operating experience is available, most closely resembles that of the Bering Sea, but there are significant differences. The most important environmental difference is the presence of ice floes and large ice features in the Bering Sea. These ice conditions make North Sea type offshore loading systems unsuitable for use in the Bering Sea without significant modifications. . Ice forces on an offshore loading system in the Bering Sea will be considerably higher than environmental forces acting on a North Sea system.

In order to develop preliminary designs for offshore loading systems and evaluate the potential performance of all Bering Sea crude oil transportation systems, a set of environmental parameters have been established for each of the three scenarios considered. The environmental parameters for which base case values have been established include:

- ice conditions,
- waves,
- water depth,
- winds,
- currents,
- tides/storm surge,
- geotechnical conditions,
- seismic conditions, and
- meteorological conditions

To test the sensitivity of the analyses to variations in the environmental conditions for each scenario, the following parameters have been varied:

- water depth, and
- geot.ethnical conditions.

These parameters were selected for variation because they are very site specific and have a significant effect on construction costs.

3.1.1 Ice Conditions

The sea ice in the Bering Sea is predominantly annual ice. There is a steady northward transport of annual sea ice through the Bering Strait during most of the winter resulting in an accumulation of annual ice north of the Strait in the Chukchi Sea. While there are occasional "breakout episodes" of ice through the Strait from the Chukchi Sea, it is uncertain whether multiyear ice is included in these episodes. The probability of a multiyear ice fragment transiting the Strait, remaining in the Bering Sea, and then interacting with an offshore loading facility at a single point, is negligibly small. Therefore, throughout this study only the effects of annual sea ice have been considered.

a) Ice Strengths

The compressive strength of annual sea ice is a function of crystal structure, temperature, salinity and strain rate. First year sea ice has a crystal structure that varies with thickness. Granular ice is found near the top, with unoriented columnar crystals below, and oriented columnar crystals near the bottom of the ice. The strength of the three types of crystal structures varies considerably (Wang 1979) as does the effect of orientation on columnar ice. For preliminary design purposes, an average strength with respect to crystal structure type and orientation has been assumed. Ice strengths are also a function of temperature and test results (Schwarz & Weeks 1977) suggest that a reduction in strength of a factor of 2.0 to 2.5 takes place as sea -ice is warmed from -10°C to 0°C. For ice strength determinations, an average ice temperature was calculated using the nominal seawater temperature (-1.8°C), an approximate weekly minimum average air temperature and a snow cover varying from 15 cm (6 in.) at the northern end of the Bering Sea to 5 cm (2 in.) at the southern end. Salinity was conservatively considered to be seven parts per thousand (Katona & Vaudrey 1973) for all ice strength calculations. Ice strengths vary with strain rate (Wang 1979, Schwarz & Weeks 1977). Since a wide range of strain rates is possible for the Bering Sea conditions considered in this study, peak ice strengths with respect to strain rate have been assumed. These conditions were used in conjunction with the most detailed experimental results published to date (Schwarz & Weeks

1977) to determine the compressive strength of ice for each scenario.

The flexural strength of annual sea ice is a function of strain rate as determined by several researchers (Dykins 1971, Katona & Vaudrey 1973, Vaudrey 1977). Due to the chemistry of sea ice, brine volume is a function of temperature and salinity. The flexural strength is measured in beam tests and these beam tests are difficult to standardize. The tests conducted by Katona & Vaudrey (1973) are considered the most representative of Bering Sea conditions and have been used for establishing the flexural strength of ice for each scenario.

Shear strength has been measured as a function of the square root of brine volume (Paige & Lee 1967) which, as mentioned above, is a function of salinity and temperature. Measurements of confined shear strength in three orientations with respect to ice crystal structure show no substantial differences (Dykins 1971). Shear strengths for each scenario were calculated assuming a salinity of 7 parts per thousand and an ice temperature estimated as described above.

b) Ice Modulus of Elasticity and Other Properties

The modulus of elasticity of sea ice has been measured by seismic means (Anderson 1958) and by static measurements (Dykins 1971). The variation of apparent elastic modulus with temperature has been determined from beam tests (Katona & Vaudrey 1973). A compilation of data on large beam tests (Vaudrey 1977) yielded an equation where the elastic modulus is a function of brine volume. This equation, combined with the ice temperature estimate described above, has been used to determine the modulus of elasticity of Bering Sea ice for each scenario.

The anisotropy of sea ice causes values of Poisson's ratio from 0.8 to 1.2 in the direction perpendicular to the crystal columns, and from 0 to 0.2 in the direction parallel to them (Wang 1981). For engineering purposes the value of Poisson's ratio for sea ice has been assumed constant at 0.33 (Weeks & Sackinger 1981).

The density of sea ice ranges from 920 to 950 kilograms per cubic meter, depending upon the volume of entrapped air (Weeks & Sackinger 1981). An average value of 935 kilograms per cubic meter (58 pounds per cubic foot) has been selected for use in this study.

Clue to the effect of surface roughness, the coefficient of kinetic friction between sea ice and steel is dependent upon the various coatings which may be applied to offshore structures. The Finnish Coating, Inerta 160, is the most durable in icebreaker service and is a good representative coating for offshore steel structures, having a kinetic friction coefficient of 0.11 at -10″C. Conservatively, a value of 0.15 has been selected for conceptual design purposes. Previous work (Tusima & Tabata 1979) showed that the presence of sea water at the surface of contact had little effect on the friction behavior. There is a lack of existing information on the frictional effects of sea ice on concrete. For purposes of this study a coefficient of kinetic friction of 0.30 for ice/concrete has been used.

c) Level Ice Characteristics

The three situations most often considered in continuous ice sheet/structure interactions are for an ice floe to ride up upon, buckle, or crush against a structure or structural member. However, the pack ice edge transition zone, as determined by sate" lite and aircraft observations, shows floe sizes and coverages less than 100 percent. This suggests an alternative analysis for the ca" culation of ice/structure interactions within 50 km (30 mi) of the ice edge, in which an ice floe striking a structure will pivot around a structural member. In such calculations, the floe size ranges near the pack ice edge are important. However, for purposes of this study it has conservatively been assumed that all possible floe sizes may contact the structures.

A level ice single-layer thickness of 30 cmto 1 m (1.0 to 3.3 ft) is typical of the freezing conditions in the Bering Sea, and random block orientations are likely. A single-layer thickness varying from 1.0 m (3.3 ft) for the northern scenario to 0.6 m (2.0 ft) for the southern scenario have been used in this study.

Multiple rafting occurs when several ice floes are laying on top of one another and become frozen together. At the freely-floating southern edge of the pack ice, several researchers (Martin & Kauffman 1979, Pease 1980, McNutt 1980, Bauer & Martin 1980, Squire & Moore 1980) have noticed triple and quadruple rafting of 30 cm (1 ft) floes to a total ice thickness of more than one meter (3.3 ft). However, melting conditions often prevail at the ice edge, and the single floe thickness at the edge is probably less than in those parts of the northern Bering Sea with restricted ice movement, implying that the normal multiple-rafted ice thickness will be in the 1 to 2 m (3.3 to 6.6 ft) range. A maximum rafted thickness varying from 2 m (6.6 ft) for the northern scenario to 1.2 m (4 ft) for the southern scenario has been used in this study.

d) Ice Ridges

Annual ice ridges have many voids and are held together by adhesion of the ice blocks from freezing shortly after ridge formation, and also by a layer of refrozen ice near the water line (Ralston 1979, Gladwell 1976, Vaudrey 1979). This is a highly variable natural process, depending upon ice block thickness, temperature before ridge formation, weather after formation, and other factors. There has been notable research on the generation of new annual ice during the winter from open leads in the Norton Sound, but there have been only the U.S. Coast Guard Polar-Class icebreaker cruises into the Bering Sea ice pack, with ice ridge profiling, to help define ridge sizes there (Voelker et. al. 1981 b). The 1982 cruise produced numerous ridge profiles (Voelker et al. 1982), employing visual observations, drilling of ridges, and sonar measurements. Using the recorded profiles of ridges in the vicinity of each of the three scenarios, average and maximum observed ice ridge profiles have been developed. There is insufficient data available on which to base a meaningful statistical extrapolation of observed ridge size to 100 year and 1 year maximum ridge sizes. However, for conceptual design purposes, the 100 year and 1 year ridge profiles selected are approximately equivalent to 1.5 and 1.0, respectively, times the envelope of values from all the observed profiles from the vicinity of each scenario.

e) Ice Coverage and Concentration

There is a high year to year variability in ice edge extent, as well as a variation from week to week caused by the movement of storm tracks through the Bering Sea region. One dominant pattern of ice movement is from Norton Sound towards the southwest, driven by winds from the northeast, along the southern and central regions of the Bering Sea. Such winds produce a mesoscale tension in the ice of Norton Sound, leading to extensive open water and refreezing of new ice there. Thus, there is an ice production region in Norton Sound, a transport to the southwest, and a melting of the pack ice edge in the southern/central Bering Sea, in which the pack ice at the edge replaces itself up to eight or ten times per season. This produces a favorable situation for navigation by ice-going vessels proceeding into the Bering Sea from the south, since there are many open leads in the ice en route.

This is not a consistent pattern, though. Ice has been observed moving from Norton Sound towards the west, into the Navarin Basin, and also towards the northwest, through the Bering Strait (Pritchard 1982, Pease 1982). A more detailed study (Overland & Pease 1982) of twenty-three years of storm track climatology of the Bering Sea (for October through March) shows that sea ice extent in a given winter is primarily controlled by the track of storms and secondarily by the number of storms. "In heavy ice years, storm behavior results in advection of cold, dry air from Alaska and the Arctic over the" ice growth regions in the coastal polynyas and vigorously drives the ice southward. In light ice years there are more storms, with storms propagating up the Siberian side. This exposes the ice to warm, moist air from the Pacific, drives the ice northward to the limits of the internal pack ice strength, and closes the polynya growth region" (Overland & Pease 1982).

The empirical probabilities of the ice edge limit at semi-monthly intervals (November 1 through July 15), at the 0%, 25%, 50%, 75% and 100% probability levels, have been constructed from all available sources (Webster 1981). These charts have been used to determine the period of time during which there is a 100% probability of ice coverage in each scenario area. The period of time during which there is any possibility of ice coverage (greater than 0% probability) has also been determined for each area.

By international agreement the okta system is used to describe the extent of ice coverage. An ice concentration of one-eighth (1 okta) or more defines the pack edge. Total ice coverage is eight-eighths or eight oktas. The extent and concentration of sea ice in the Bering Sea are shown for semi-monthly intervals in Figures 3-1, 3-2 and 3-3 (Potocsky 1975). A compilation of average year ice concentration data at semi-monthly intervals (Brewer et al. 1977) for each offshore loading site has been prepared and are presented in Chapters 4, 5 and 6 in tabular form showing ice concentration (oktas) versus frequency of occurrence. Since these tables are based on large scale semi-monthly averages observed over a limited period of time, zero days of several levels of ice concentration appear in the tables. Obviously, some days of each level of concentration actually must have occurred but were not observed.

f) Ice Floe Velocity

Velocities of ice floe movement in the Bering Sea have often been determined from the comparison of satellite images of the same region taken one day apart. As such, an average velocity field is computed. The resolution of individual floes by Landsat makes possible such velocity field maps, whereas the lower-resolution NOAA

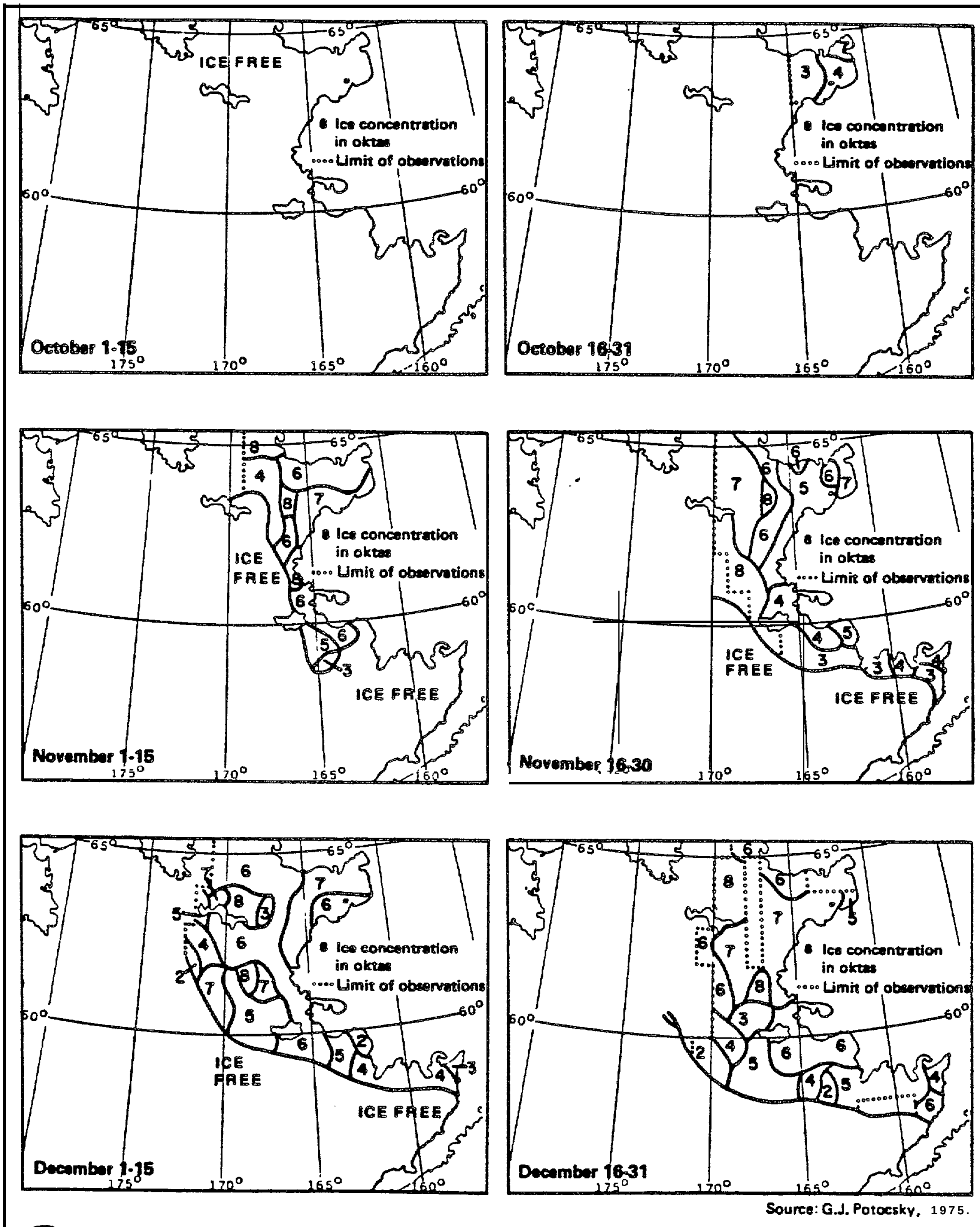

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Figure 3-1. Extent and concentration of sea ice, October through December.

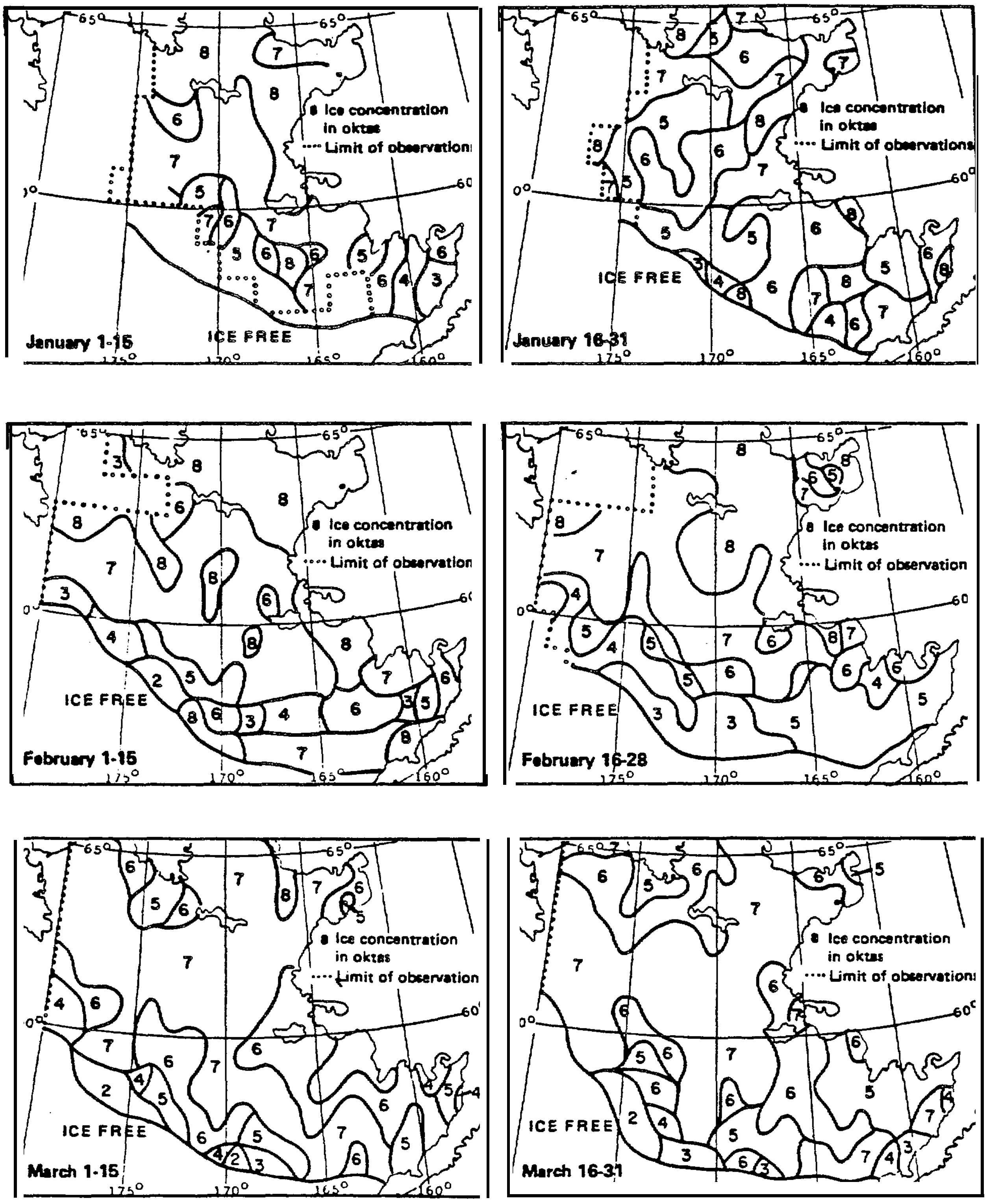

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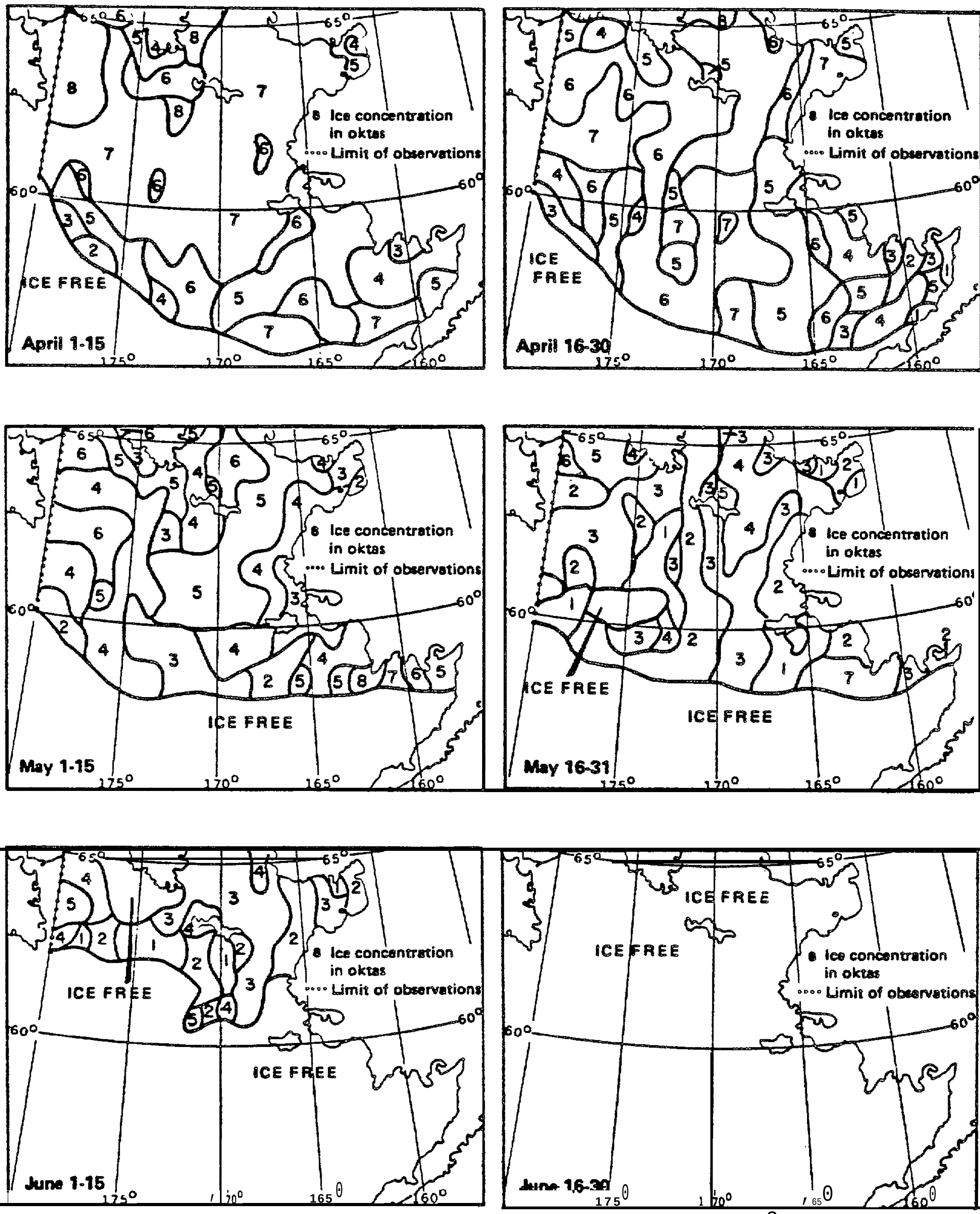
Figure 3-2. Extent and concentration of sea ice, January through March.



Source: G.J. Potocsky, 1975.

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Figure 3-3. Extent and contraction of sea ice, **April** through **June**.

satellites are useful in determining the ice edge on a daily basis.

Wind direction and tracks of storms are the dominant driving influence upon the ice movement in the Bering Sea. From velocity field maps, the presence of boundaries in a multitude of different orientations for the Bering Sea ice pack, plus the spatial wind gradients and storm track movements, lead to an abundance of regions of pack ice convergence and divergence, which are shifting on a daily basis. Throughout the Bering Sea there is frequent ice divergence, and navigation there is expected to be relatively easy on most occasions.

The maximum velocity of ice in a region relatively free from near-surface water currents is approximately 2.5 percent of the average wind speed. The Bering Sea area of interest has winds exceeding 24 meters per second (48 knots) approximately 1 percent of the time in the winter months. If a maximum sustained windspeed over the open ocean of as much as 30 mps (60 k) is assumed, the corresponding ice floe velocity is 0.77 mps (1.5 k), roughly comparable to the satellite-based observations previously mentioned. For purposes of ice/structure interaction in the Bering Sea, a maximum ice floe velocity of 0.75 mps (1.5 k) has been used.

g) Superstructure Icing Rate

An important environmental condition which must be expected in the Bering Sea is spray ice accretion on ships and offshore loading structures. Accretion of as much as 2.5 cm (1 in.) of ice in three hours time can lead to an extra gravity load of hundreds of tons. The weather conditions which produce spray ice accretion are cold high winds, cold water, and waves producing spray droplets which freeze upon contact. The accurate prediction of the quantity of ice buildup is difficult. A nomogram for spray icing and an isograph indicating areas where the most severe icing is likely to occur at any time have been derived from ship reports (Wise & Comiskey 1980). The portion of the isograph of interest for this study is reproduced in Figure 3-4. The definitions of icing categories used in the figure are given in Table 3-1.

TABLE 3-1

ICING RATE CATEGORY DEFINITION

CATEGORY	ICING RATE cm/3 hr	(in./3 hr)
Light.	0.6-1.3	(0.25-0.50)
Moderate	1.3-1.9	(0.50-0.75)
Heavy	1.9-2.5	(0075-1.00)
Very heavy	2.5-3.2	(1.00-1.25)
Extreme	·3.2	(1.25)

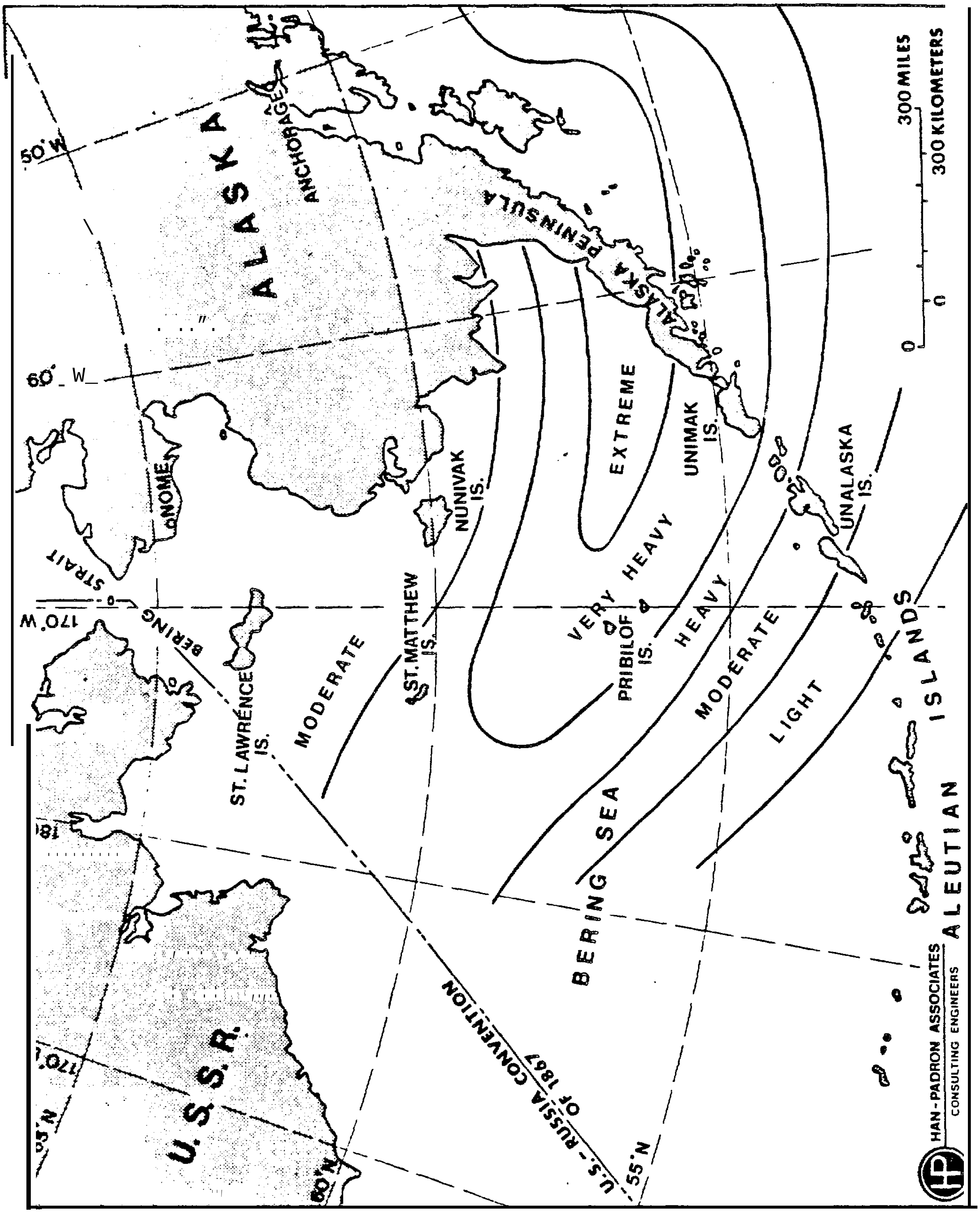

Figure 3-4. Isograph for superstructure spray icing categories.

3.1.2 Waves

The generation of waves in deep water depends on fetch, wind speed, and wind duration. In the relatively shallow and protected waters of Norton Sound, water depth and wave direction need also to be considered. Maximum 100-year wave heights for each of the offshore loading sites were calculated based on the procedures described in "Shore Protection Manual," 1977, U.S. Army Coastal Engineering Center.

3.1.3 Water Depth

For each location selected, a base case water depth was determined from NOAA nautical charts for the Bering Sea. The probable maximum and minimum water depths for each scenario area, for use in the sensitivity analyses, were also determined. All water depths are referred to mean low water (MLW).

3.1.4 Winds

The values of maximum one-minute average windspeeds for a 100-year return period, based on measurements taken at various coastal stations, are given in the "Climatic Atlas" (Brewer et al. 1977). The values for each of the three offshore loading system sites were determined by interpolation of data from the nearest stations.

In order to determine the effect of wind forces on structures and mooring operations, it is not sufficient to know only the sustained one-minute average wind speed. Three second gust and one hour average wind speed values were extrapolated from sustained one minute windspeeds using established wind speed relations (Myers et al. 1969).

3.1.5 Currents

The general flow through the Bering Sea is northward. Water is transported from the North Pacific through the Bering Strait into the Chukchi Sea. Many irregularities exist due to St. Lawrence Island and the Alaskan and Siberian coastline. Other topographically induced variations occur when the flow passes large embayments such as Norton Sound.

Surface current information for the summer and winter season is shown in Figure 3-5 (Brewer et al. 1977) based on the "U.S. Navy Marine Climatic Atlas of the World." More recent studies have differed with these depictions somewhat. Currents for design purposes are site specific and were estimated for preliminary design purposes based on Figure 3-5, Draft or Final Environmental Impact Statements for each lease sale area and a variety of other sources.

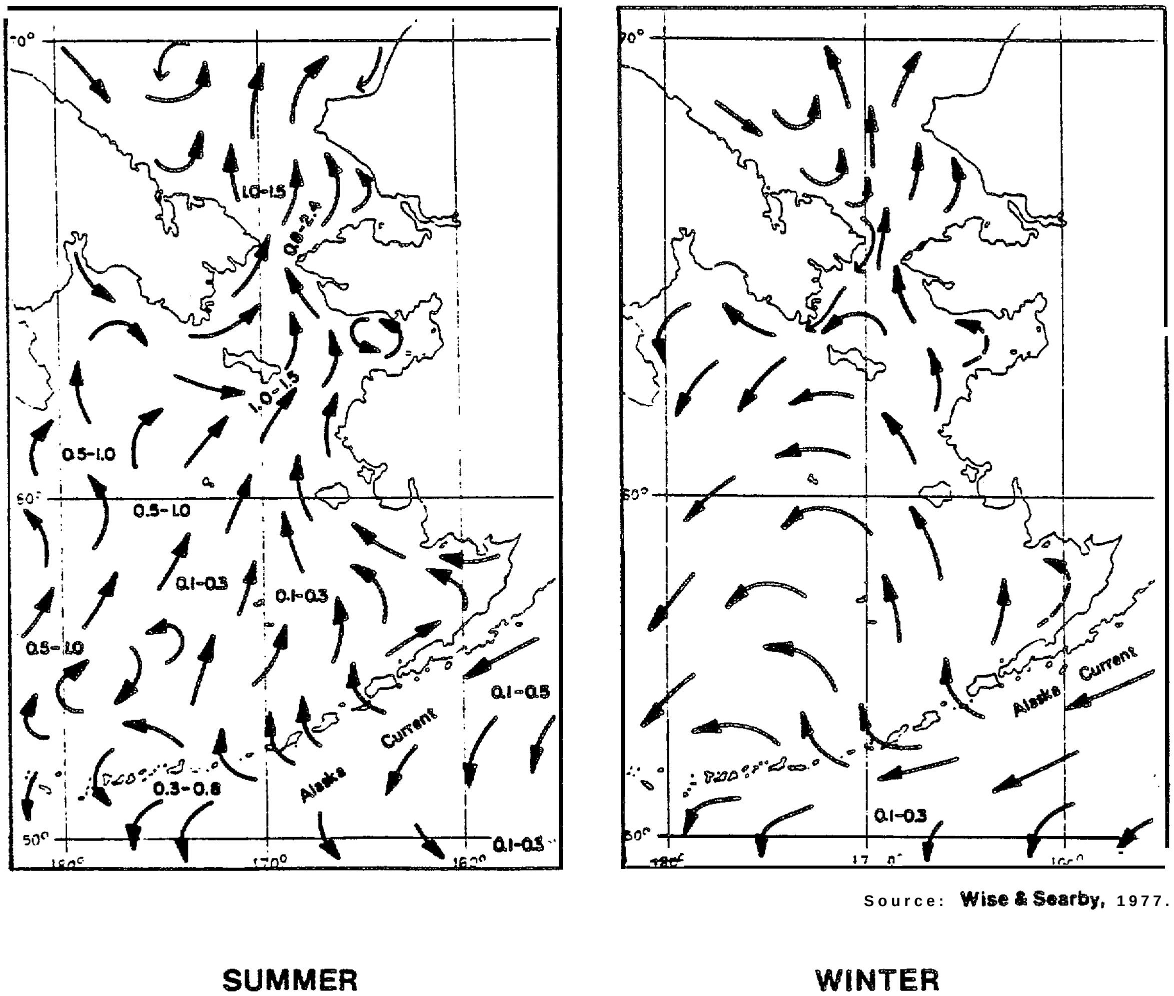

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Figure 3-5. Surface currents in the Bering Sea.

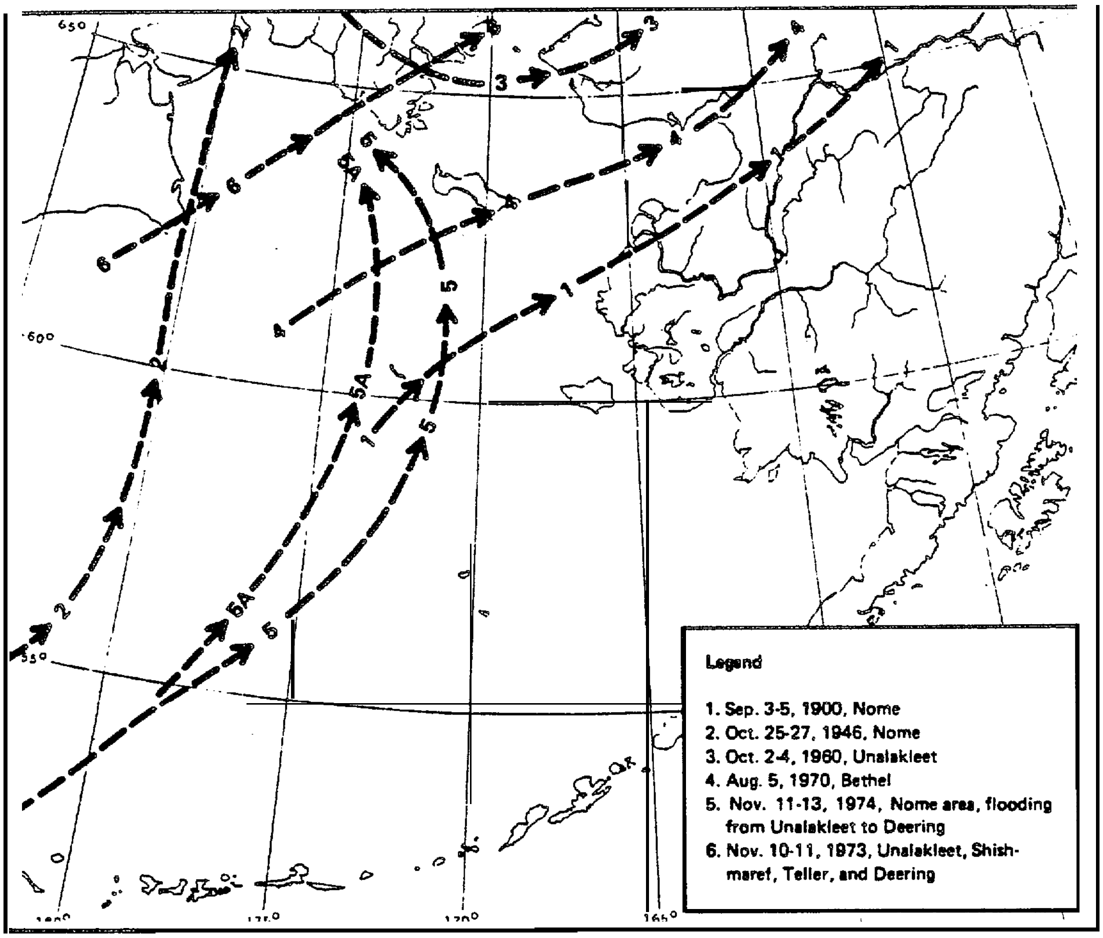
3.1.6 Tides/Storm Surge

Tide information is available from twenty-six stations located around the perimeter of the Bering Sea and on St. Lawrence, St. Matthew and St. Paul Islands (Brewer et al. 1977). The tide range for each loading terminal site was estimated by interpolation of the information from the two or three nearest stations.

Storm surges are increases in sea level above astronomical tide levels due to severe storms. Records of storm surges are incomplete, although Nome has been affected by large storms where water levels ranged from 0.9 m (3 ft) below mean low water to 4.6 m (15 ft) above (National Petroleum Council 1981). The tracks of recorded storm surge occurrences are shown in Figure 3-6 (Brewer et al. 1977). The storm surge value for preliminary design purposes for Northern Bering Sea offshore loading terminal sites was estimated based on surge levels recorded at Nome, allowing for the distance from shore of the terminal. For the open water sites in the Central and Southern Bering Sea, storm surge is not a significant factor. As a precautionary measure, for preliminary design purposes a value of 1.0 m (3.3 ft) was used.

3.1.7 Geotechnical Conditions

Capital costs of offshore structures can be quite sensitive to the nature of the seabed and site-specific data is essential for the



Source: Wise & Searby, 197'7.

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Figure 3-6. Tracks of storm surge occurrences in the Bering Sea.

design of these structures. Information on the general nature of the seabed soil is available from a number of sources (Larsen et al. 1980, Fisher et al. 1979, Marlow et al. 1979 & 1980, Carlson & Karl 1981, Gardner et al. 1979') but specific soil properties for foundation design purposes is not available. For each scenario, base case soil engineering properties have been assumed which are typical for the type of seabed sediments in the area. A second set of soil properties, significantly different than the base case properties, was also selected to illustrate the sensitivity of the capital costs to the geotechnical conditions.

3.1.8 Seismic Conditions

Considerable data is available regarding seismic conditions in the Bering Sea (USDOI 1981a, 1981b & 1983, Marlow et al. 1979, 1980 & 1981, Larsen et al. 1980 and Carson & Karl 1981). In the absence of site specific studies, the preliminary designs of the offshore structures have been based on the recommendations contained in "API Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms," American Petroleum Institute, January 1982.

3.1.9 Meteorological Conditions

The dominating physical phenomenon in the Bering Sea is the seasonal change in the position of the Aleutian low, which executes an annual clockwise rotation. In early autumn, the Aleutian low migrates out of the northern Bering Sea and crosses the Alaska Peninsula. In winter, the low is usually located in the Gulf of Alaska. In late winter, the mean center of the Aleutian low moves to the southwest and in early spring it moves northward into the northern Bering Sea. In March, this low allows storms to migrate or be guided over the Gulf of Alaska and the Bering Sea.

Annual precipitations and temperatures have been recorded at a number of stations throughout the area of interest for this study (Alaska OCS Office 1980) . Values for offshore loading sites were interpolated from the data available from the two or three stations closest to each site.

Optimum visibility periods throughout the Bering Sea vary according to the time of year. September and October usually offer the viewer the most benign atmospheric conditions while the mid-winter (blowing snow) and mid-summer (prolonged fog) months present the greatest visual impairment (Brewer et al. 1977). The annual percent frequency of occurrence of various precipitation types and visual obstructions, which include rain or drizzle, freezing rain or drizzle, snow or sleet, fog, smoke or haze, and blowing snow, were recorded at the stations previously mentioned. The values from the two or three stations closest to each offshore loading site were interpolated to establish preliminary design values.

3.2 CALCULATION OF ENVIRONMENTAL FORCES ON OFFSHORE FACILITIES

3.2.1 Ice Forces

Significant ice forces on offshore loading and storage facilities occur at all three scenario locations. "The size and shape of the structure and the local ice feature dimensions determine the magnitude of the ice forces and their significance in the overall design of each structure. The ice features of primary concern in the study areas are first year ridges, and rafted ice. First year ridges are linear ice features created by motion interference between two ice sheets. Rafted ice is an ice sheet consisting of two or more ice sheet thicknesses as a result of overriding.

Ice forces have been determined for each structural configuration that was considered for the study areas to aid in the selection of optimum system designs. The large variation in water depth and ice conditions among the three Bering Sea study areas leads to the presumption that a different type of structural concept may be optimal for each scenario. Therefore, all theoretical approaches followed for the calculation of ice forces on various offshore facility shapes are presented below.

In general, the forces imposed by ice on offshore facilities are dependent on the following properties of the ice and offshore structure:

Ice Properties

- formation (sheet, first-year ridge, rubble pile),
- thickness,
- areal extent,
- compressive, flexural, tensile and shear strengths,
- temperature,
- age,
- strain rate,
- crystal structure,
- salinity,
- elastic modulus, and
- chemical and physical impurities.

Structure Properties

- plan shape and dimension,
- ice/structure interaction surface (vertical, or conical),
- ice/structure friction coefficient,
- structure elasticity, and
- dynamic response characteristics (mass, stiffness and damping).

The magnitude of the ice forces acting on a structure in the Bering Sea are limited by either the ice. feature failure and clearing forces or the environmental driving forces, whichever are less. The geometry of the structure and the formation of the ice feature govern the failure mode of the ice. Applicable failure modes include:

- crushing,
- buckling,
- bending in the vertical plane,
- bending in the horizontal plane, and
- double-sided shear (along vertical planes).

A vertical-sided structure will cause ice to fail by crushing, buckling, shearing along vertical planes or bending in the horizontal plane, depending on the ice formation and characteristic dimension and the structure diameter. Conical structures generally induce vertical deflection of the ice feature, causing primary failure by bending. In instances where large adhesion bonding strengths of a stagnant ice floe to a structure exist, alternate failure modes may include crushing, buckling or double-sided shear along vertical planes. Selection of the optimum concept for an offshore mooring and/or storage structure requires that the ice forces on both cylindrical and conical profiles be evaluated.

a) Cylindrical Structures

The theory of ice crushing on a cylindrical surface is a classic topic in the field of ice mechanics and accounts for the bulk of the research effort in this field over the last twenty-five years. Even so, the amount of field data applicable to the size of structures required for mooring and storage operations in the Bering Sea environment is minimal and hence the validity of even the latest state-of-the-art theories remains largely unsupported. A complete review of this topic is outside the scope of this study and the reader is referred to Neill (1976) and Croasdale (1980) for further information.

Korzhavin (1962) prepared the early framework for solution of this problem with the empirical relationship:

$$F = I\, m\, k\, s_c\, h\, d$$

where: F = ice force in crushing on a vertical-sided structure;

I = indentation fact-or which is dependent on the aspect ratio (d/h) and which takes into account the three-dimensional effects of the ice stress field in front of the structure;

m = shape factor to account for the various plan shapes of ice indenters;

k = contact factor which accounts for the actual degree of ice-structure contact achieved at any instant of time;

s_c = ice compressive strength;

h = ice thickness; and

d = characteristic structure dimension at the waterline (diameter or width).

Since that time, most of the research has been directed towards further defining the values of I, k and s_c. All three of these factors are interrelated in that they depend on many of the same parameters, namely, aspect ratio, rate of loading, crystal structure and orientation, and ice temperature. The exact definition of the functional relationship among these parameters has so far gone unsolved by theoretical analysis because the fracture mechanism and failure criterion of ice, as a viscoelastic, anisotropic material, has not been fully established.

Plasticity theory, and its Lower-and-Upper-Bound Theorems, simplify the problem by assuming ice to be an isotropic, elastic-plastic material while neglecting the effect of contact dependence (Croasdale et al . 1977, Michel & Toussaint 1977, Ralston 1977b, 1978).

In-field and small scale ice force measurements have been conducted by many investigators including Frederking & Gold (1975), Michel & Toussaint (1977), Nevel et al. (1972), Schwarz et al. (1974) , and Croasdale et al. (1977), among others. Data from these measurements is quite sparse and often of limited application to site specific ice conditions and structural dimensions. In general, though, ice strength has been shown to possess a strong dependence on loading rate and a possible dependence on aspect ratio (Croasdale 1980).

The procedure used to establish the design ice compressive strength for each scenario is outlined in Section 3.1.1. For each scenario, the design ice strength has been selected based on the minimum expected ice temperature and the strain rate corresponding to the peak ice strength. These peak values were then used for all structures without consideration of possible decreases in strength due to variations in strain rate, temperature or aspect ratio.

The shape factor, m, is defined as 1.0 for a flat indenter and 0.9 for a circular indenter. These values are in universal agreement among all references and a value of 0.9 is applicable to the circular or near-circular structures considered in this study.

Values for the contact, factor, k, which appear to be universally accepted when separated from the indentation factor, are between 0.3 and 1.5. The value of k decreases towards 0.3 as the ice brittleness increases and tends towards 1.0 as the ice ductility increases. For perfect and total contact k equals 1.0 and may increase beyond 1.0 up to 1.5 during conditions of ice adfreeze to the structure. The contact factor actually selected is scenario specific and depends on the ice movement, coverage, temperature and thickness and the structure size, shape and compliability.

The indentation factor, I, has received significant attention in the form of direct laboratory and field measurements and theoretical modeling. The following equation was first proposed by Afanas'ev et al. (1971) and later shown by Neill (1976) to agree quite well with experimental test data by Allen (1970), Assur (1971) and Schwarz et al. (1974):

$$I = (1.0 + 5(h/d))^{0.5}$$

Croasdale's et al. (1977) plasticity analysis utilizing failure criteria developed basically for metals, results in indentation factors not far from those proposed by Afanas'ev. Ralston (1978) applied the plasticity theory by fully generalizing the von Mises yield criterion to account for material anisotropicity, pressure sensitivity and unequal strengths in tension and compression. He demonstrated that this approach leads to satisfactory agreement with the laboratory test data of Michel & Toussaint (1977) for two-dimensional in-plane loading of freshwater, columnar-grained, laboratory grown ice at -10°C. Three-dimensional aspects, continuous crushing phenomena and plastic buckling, all known to have a reducing effect on the indentation value, were not addressed in Ralston's analysis and the results should be used basically as a qualitative interpretation of large scale ice interactions.

Figure 3-7 shows the difference among the theoretical relationships for indentation factors as proposed by Afanas'ev et al., Croasdale et al., and Ralston. Ralston's analysis, resulting in the highest indentation factors, has been used for this study as a

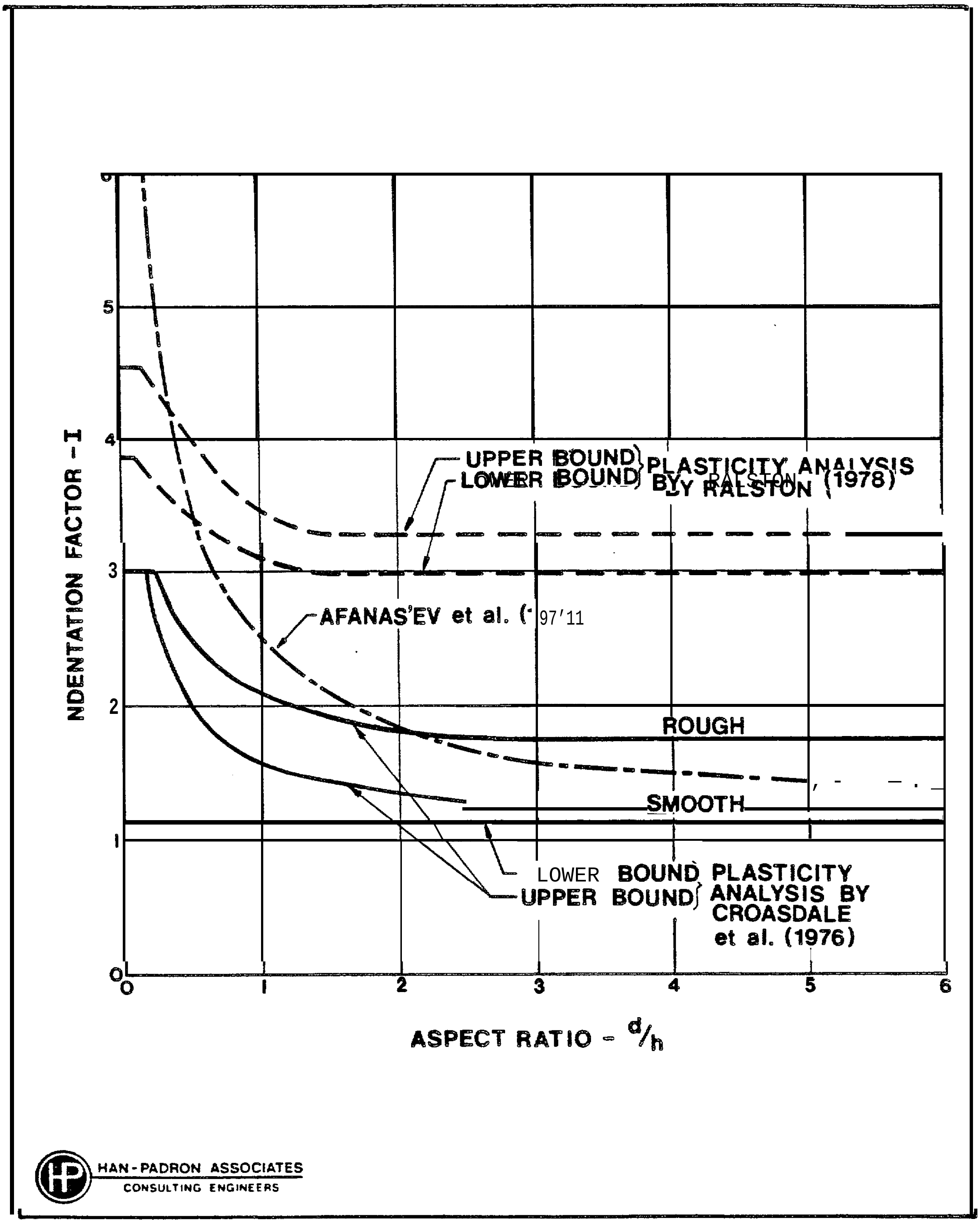


Figure 3-7. Comparison of proposed indentation factors.

conservative approach in the preliminary design phase.

In calculating the crushing force on a cylindrically shaped structure using Korzhavin's formula, the ice thickness, h, has been taken as the full ice thickness of sheet or rafted ice or as the consolidated thickness for first-year pressure ridges. The unconsolidated portion of the ridge feature is assumed to crush or shear off without significant additional load to the structure. Specific floe sizes with embedded ridges may occasionally fail at less than the crushing force by in-plane bending or double-sided shearing mechanisms. Experience indicates, however, that for the range of floe and ridge sizes established for each scenario, these alternate failure mechanisms will be the exception and not the rule.

b) Conical Structures

Conical structures cause ice features to bend and fail by flexural mechanisms. Bending failure has been studied both analytically (Afanas'ev et al. 1971, Bertha & Danys 1975, Ralston 1977a) and experimentally (Sorensen 1977, Edwards & Croasdale 1976, Pearce & Strickland 1979), with the major emphasis on determining the sequence of failure mechanisms and identifying all feasible failure interaction modes. Bending failure loads are comprised of separate components for failure of the ice and for clearing the ice feature around the structure. Sheet ice and first-year ridges exhibit different failure mechanisms in interaction with a conical structure, therefore, each will be discussed separately.

Sheet Ice

Excellent agreement between model tests conducted on sheet ice interacting with a sloping surface (Edwards & Croasdale 1976) and an analytical plastic description of the phenomenon has been achieved by Ralston (1977a) with the following equations:

$$R_H = (A_1 s_f h^2 + A_2 P_w g h D^2 + A_3 P_w g h_R (D^2 - D_T^2)) A_4$$

$$R_V = B_1 R_H + B_2 P_w g h_R (D^2 - D_T^2)$$

where: R_H = horizontal force on cone;

R_V = vertical force on cone;

s_f = flexural strength of ice sheet;

$P_w g$ = weight density of water;

h = ice sheet thickness;

h_R = ice ride-up thickness;

D = waterline diameter of conical shape;

D_T = top diameter of cone;

$A_1, A_2 = f(D, s_f, t)$;

$A_3, A_4, B_1, B_2 = f(a, u)$;

a = cone angle measured from horizontal; and

u = ice-structure friction coefficient.

Graphs for A_1, A_2, A_3, A_4, B_1 and B_2 are given in the noted reference.

This approach by Ralston idealizes the floating ice sheet as an elastic-perfectly plastic plate supported by an elastic-perfectly plastic foundation, using a pure bending failure criterion. The first two terms of the R_H equation account for the mechanism of flexurally failing the advancing ice sheet, while the third term accounts for the clearing of the broken ice pieces over or around the cone's surface. The analysis used in developing these equations follows the approach of an upper bound determinant"ion using plastic limit theory.

The sequence of failure events begins with a single radial crack propagating from the center of the structure into the advancing ice sheet. This is followed by additional radial crack formations as shown in Figure 3-8. Next, circumferential cracks form at the characteristic distance from the structure and the individual ice pieces are forced to ride up the structure by the advancing sheet behind them. Peak loads coincide with the formation of the radial and circumferential cracks and are applied in a cyclic nature with minimum forces correlating to the ice ride-up components (Pearce & Strickland 1979).

It should be noted that the cone angle, a, is defined as the effective slope angle at the ice/structure interface. For a rigid structure the value of a is constant. For a compliant structure with an icebreaking conical surface, the effective interaction angle equals the physical cone angle minus the angle of inclination of the

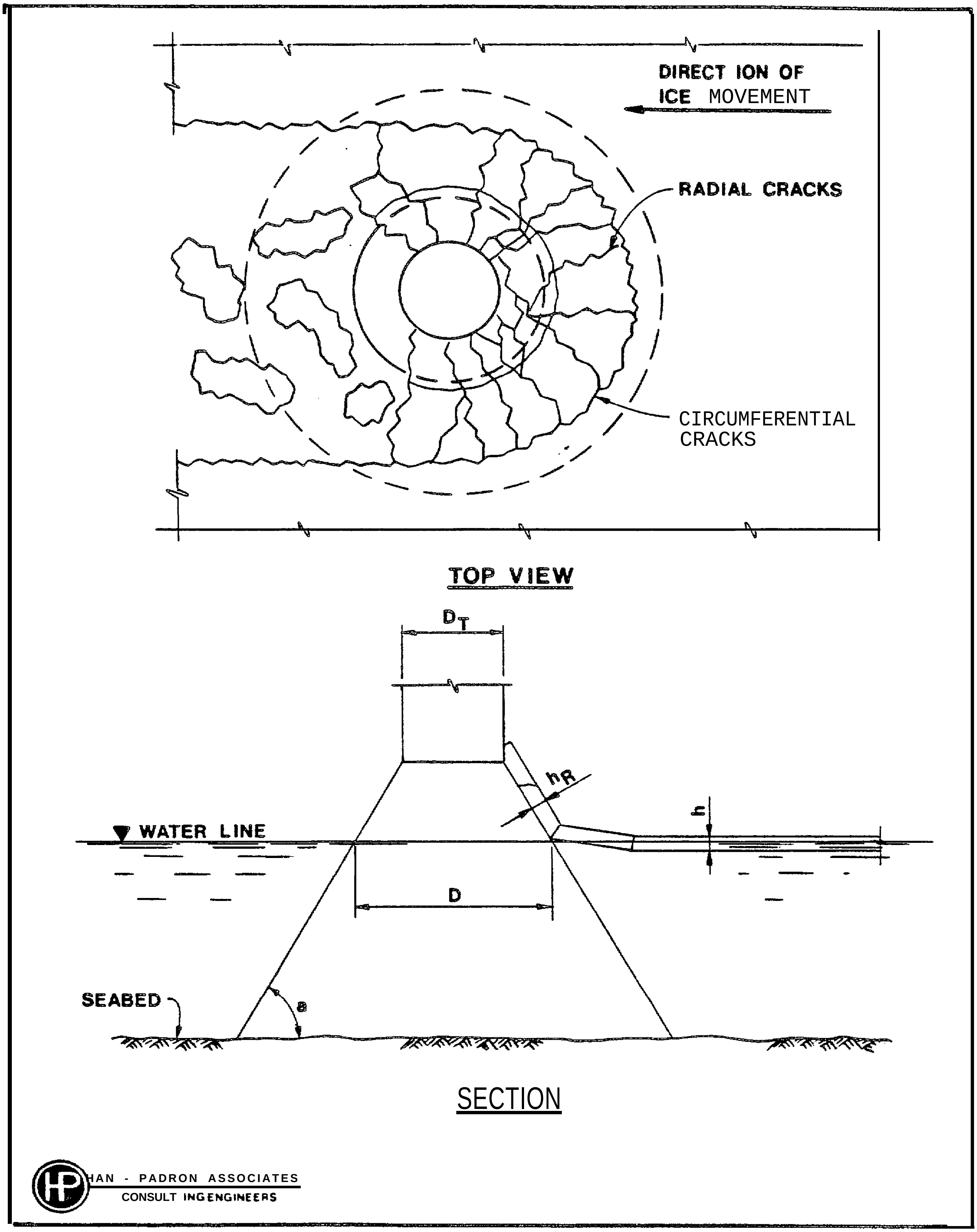


Figure 3-8. Ice sheet failure against a conical structure.

structure. For ice breaking considerations, it becomes advantageous for the tower to incline since it causes the effective interaction angle to decrease, thus reducing the horizontal component of the force necessary to fail the ice. This general concept holds true for both sheet ice and pressure ridges.

A review of all currently available failure theories for conical structures and a comparison of the various formulas can be found in Croasdale (1980) and Neill (1976). Ralston's method consistently predicts the largest total ice force for narrow, medium and wide structures, and thus seems to provide the desired upper limit bound.

Ridge Formations

First-year ridges in the three study areas will impose the greatest ice loads on the offshore structures. The ridge is assumed to be composed of broken ice pieces (rubble) loosely held together by buoyancy, gravity and frictional forces. This rubble material is believed to have properties similar to a granular material with internal angles of friction as high as 50 degrees and full-scale cohesive strengths between 35 to 70 kPa (5 to 10 psi) (Prodanovic 1979). A substantial zone of consolidation exists where the seawater is integrally refrozen with the ice rubble to form a solid ice mass. This zone of consolidation is assumed to have the same mechanical properties as those specified for the solid ice in the individual scenarios.

The analytical work to date (Croasdale 1975, Ralston 1977a, Bertha & Stenning 1979) has assumed the ridge acts as an elastic beam on an elastic foundation (Hetenyi 1946). The only known published experimental data on ice ridge failure mechanisms is by Lewis & Croasdale (1978). The analytical procedure of Croasdale (1975) and Ralston (1977a) summarized by Croasdale (1980) follows.

Assuming the consolidated ridge is uniform in cross-section, infinite in length and floating on an elastic foundation of water, the vertical force required to form the initial center crack of the ridge is given by:

$$R_{V1} = \frac{4\ I\ s_f}{Y_t\ l}$$

where: I = ridge cross-section moment of inertia;

s_f = ice flexural strength;

Y_t = distance from the neutral axis to the top of the ridge (tension surface); and

l = ridge characteristic length on an elastic foundation, given as:

$$l = (4\ E\ I\ /\ P_w g\ b)^{0.25} \quad \text{with:}$$

E = ice elastic modulus;

$P_w g$ = weight density of water; and

b = ridge width.

Although the ridge is broken with the formation of the center crack, it is not able to clear around the conical structure until secondary hinge cracks form and allow substantial rotation of the broken pieces. The mechanisms required to fail and clear the ridge feature around a conical structure are shown in stages in Figures 3-9, 3-10 and 3-11, after experimental results by Lewis & Croasdale (1978). The vertical force corresponding to the simultaneous failure of two semi-infinite floating ice beams is:

$$R_{v2} = \frac{6.17\ I\ s_f}{Y_b\ l}$$

where: Y_b = distance from the neutral axis to the bottom of the ridge (tension surface).

Simultaneous hinge crack formation almost always. results in a higher load than formation of the initial crack. Although simultaneous crack occurrence depends on a uniform ridge cross-section and strength, an unlikely probability, it is still considered a prudent approach in view of the following two circumstances.

First, the above equations do not consider the effects of the surrounding ice sheet which may increase the required failure forces for the ridge, especially in situations where the ice sheet is sizable in relation to the consolidated ridge thickness. This phenomenon is suspected to be the cause of the large discrepancies between experiment and theory for the smaller ridge size in Lewis &

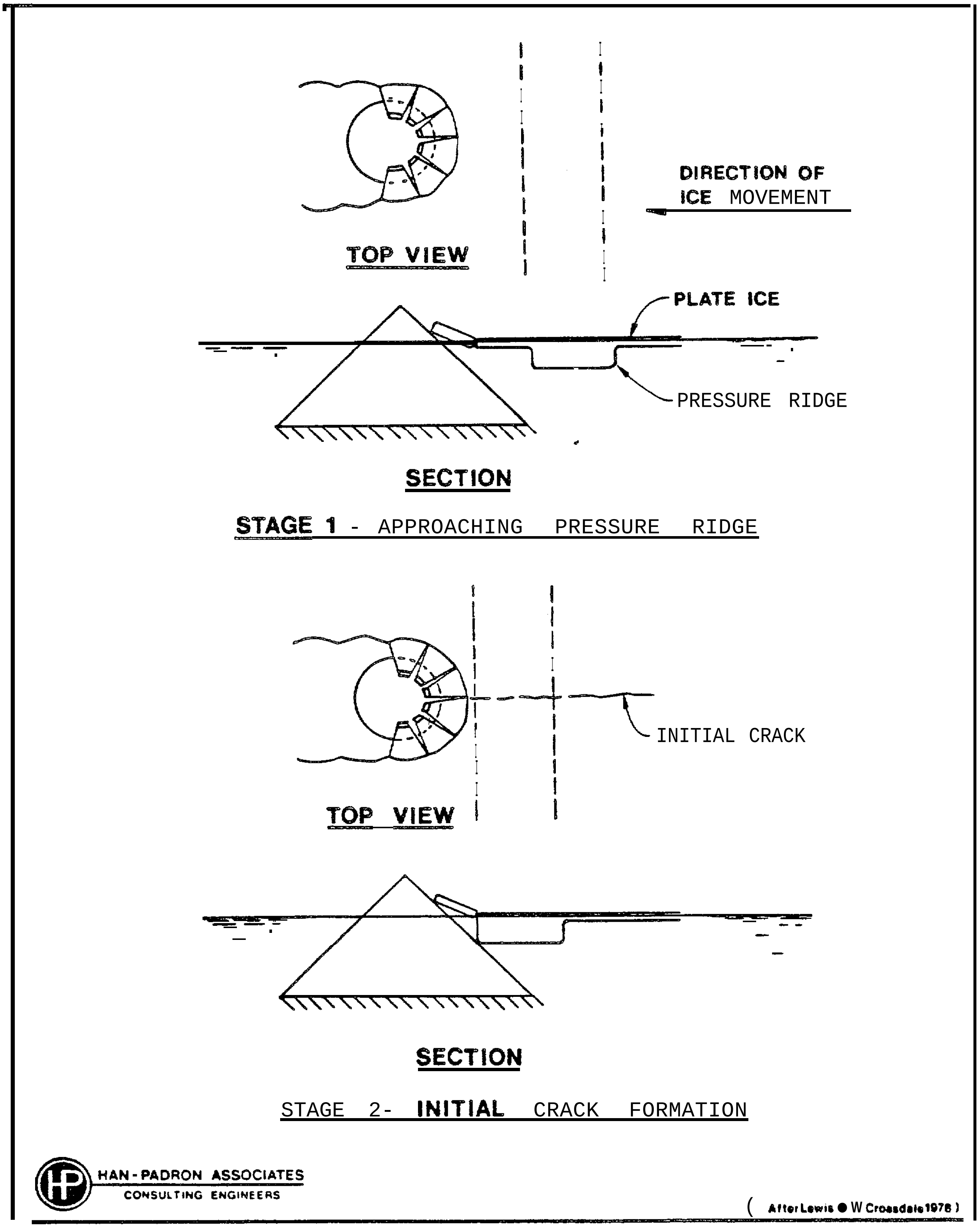
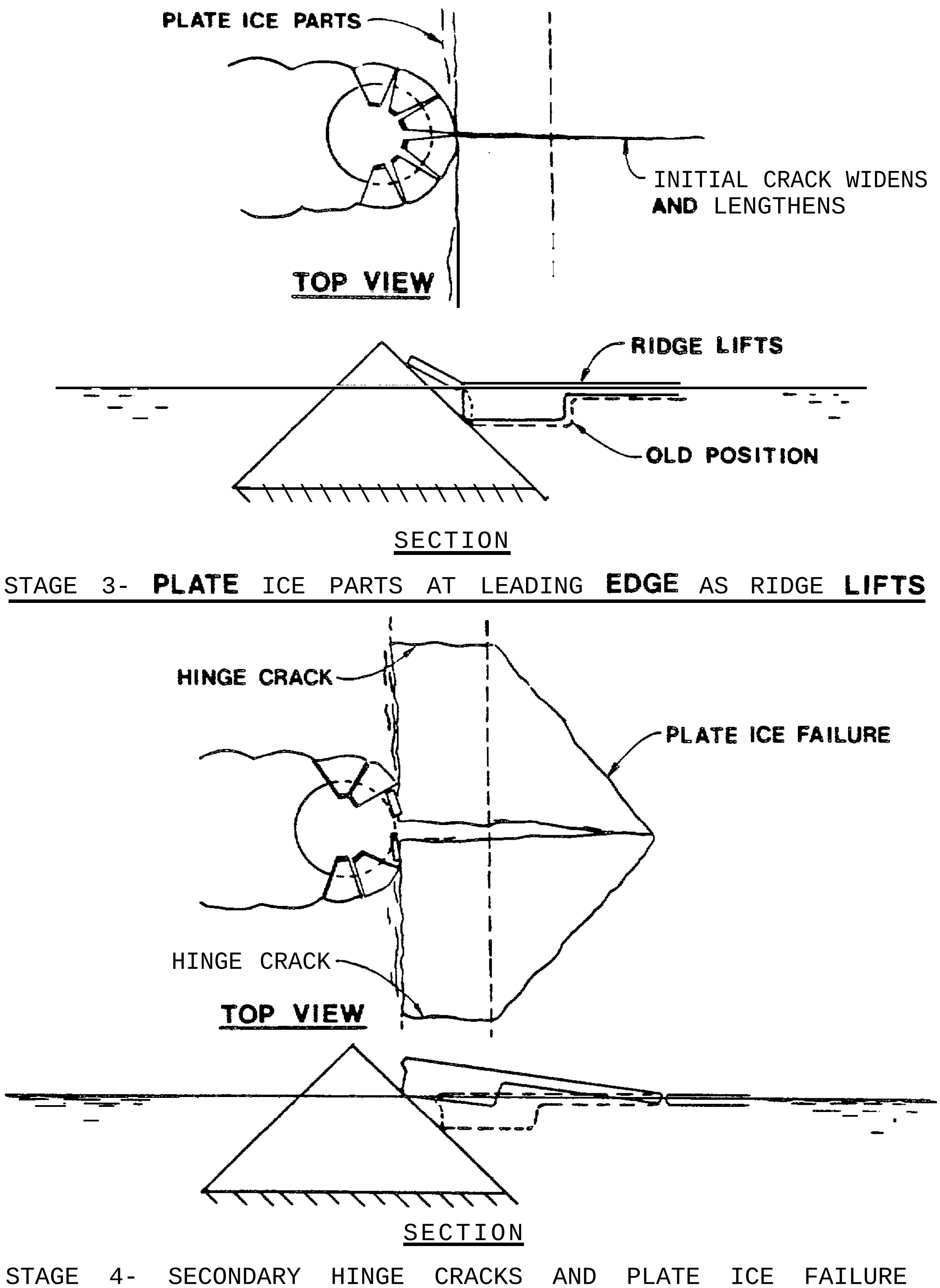


Figure 3-9. Pressure ridge failure mechanism.



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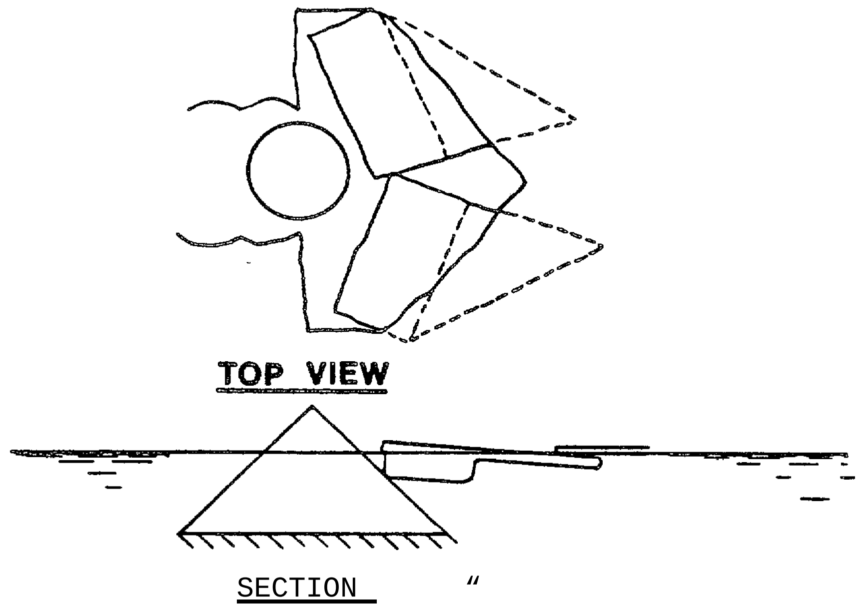
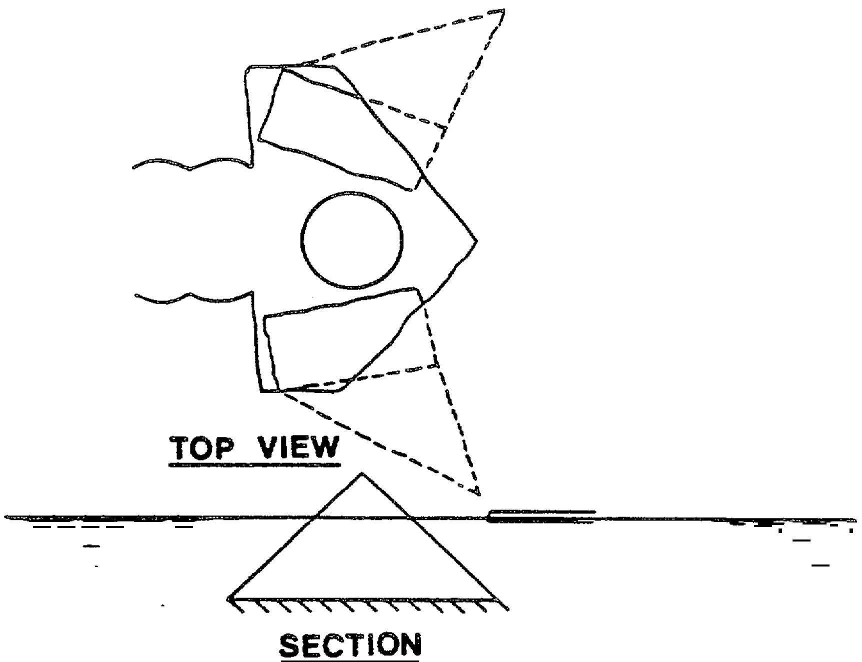
(After Lewis and Croasdale 1978)

Figure 3-10. Pressure ridge failure mechanism (continued).



STAGE 5- **BROKEN RIDGE HALVES** SLIDE DOWN **FACE OF CONE UNDER** UNBROKEN PLATE **ICE**



STAGE 6- BROKEN RIDGE HALVES ARE FULLY CLEARED AROUND STRUCTURE

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(After Lewis and Croasdale, 1978)

Figure 3-11. **Pressure** ridge failure mechanism (continued).

Croasdale's (1978) work (Croasdale 1980).

Secondly, stemming from the elastic beam analogy work of Hetenyi (1946), Ralston (1977a) proposes that extension of the elastic model to beams of finite length leads to the prediction that vertical forces for flexural failure will increase with decreasing ridge length. Hence, it is possible that, unless alternate failure or clearing interactions are introduced, shorter ridges may exert greater forces on the structure than longer ridges. Since no further information is available at this time, the simultaneous formation of hinge cracks is considered a justifiable assumption.

Based on the assumed strength of the unconsolidated rubble portion of the ridge, the load required to crush or shear through the rubble mound is considerably less than the peak force required to fail and clear the consolidated ridge portion. Since the peak loads from each failure mechanism occur at different stages of the ridge passing, the controlling design load is that which corresponds to the consolidated ridge failure.

The above formulas represent only the vertical force required to cause failure of the ridge, the resulting horizontal force is solely dependent on the slope angle, a, and the coefficient of friction, u, at the ice/structure interface. The relationship between the vertical force, R_v, and the horizontal force, R_H, is given by:

$$R_H = R_V \frac{\sin a + u \cos a}{\cos a - u \sin a}$$

c) Vessels

Considerable research, both theoretical and experimental, has been conducted regarding the force exerted by sheet ice on icebreaking vessels and a much lesser amount on the force exerted by ridge breaking and clearing.

Sheet Ice

As an unbroken ice sheet impacts the bow of the vessel, local crushing is observed at the contact point until the contact area increases to the extent that the compressive stress is below the compressive strength of the ice. Failure then occurs in bending, with the mathematical model for this condition being an infinite plate on an elastic foundation. The first general mathematical form for expressing the variables involved in icebreaking resistance is attributed to Kashteljan et al. (1968). The equation has three terms to account for:

- the resistance due to the breaking of the ice by the bow, including the effect of friction between the hull and ice,
- the resistance due to the submerging and overturning of the broken ice pieces and the frictional forces devel-

oped when buoyancy forces the broken ice against the hull and the underside of the unbroken ice field, and

- the resistance due to extracting momentum from the moving vessel and imparting it to the broken ice pieces.

More recent work by Lewis and Edwards (1970) resulted in the following expression for continuous mode icebreaking resistance, also containing three terms representing the same three components:

$$R_i = C_1 \sigma_f h^2 + C_2 \rho_i g B h^2 + C_3 \rho_i B h V^2$$

where: R_i = resistance of Ice;

C_1, C_2, C_3 = resistance coefficients;

σ_f = ice flexural strength;

h = ice thickness;

ρ_i = ice mass density;

g = gravitational acceleration;

B = ship beam; and

V = ship speed.

Ridge Formations

When the vessel encounters a ridge, Tortes significantly higher than those resulting from sheet ice occur. These ridge encounter forces are basically in two forms, breaking and clearing. Ridge breaking forces have been calculated in a manner similar to that described above for ridge encounters with conical structures based on the analytical procedure of Croasdale (1975) and Ralston (1977a) and summarized by Croasdale (1980). To determine ridge clearing forces a mathematical model was developed to account for the ridge clearing mechanism. The forces exerted by the vessel to overcome the buoyancy properties of the ridge in forcing it under the hull was determined and the frictional resistance resulting from the hull/ridge contact was calculated.

d) Environmental Driving Force

The environmental driving force on an ice floe will limit the maximum force available to cause failure of sheet or ridge features against a fixed structure. The driving force on ice floes in large bodies of water is primarily dependent on wind conditions. The wind generated driving forces on an ice surface can be derived from the classical expression for drag (Danys 1977), summarized as follows:

$$F = 0.054\ C_{10}\ V_{10}^2\ S$$

where: F = total force exerted by wind drag over an ice surface (lbs);

C_{10} = drag coefficient at the 10 meter elevation level;

V_{10} = wind speed in miles per hour; and

S = ice sheet surface area (ft^2).

Danys (1977) gathered values of C_{10} for various snow surfaces from investigations performed between 1936 and 1973 and recommends an average value of 0.0022 for unridged rough ice.

Fewer experimental results are available for drag coefficients over ridged ice. Smith & Banke (1973) suggested multiplying the level ice drag coefficient by a correction factor of 2.0 to account for additional drag on ridge formations. Arya (1973) suggested a correction factor of approximately 1.4. For preliminary design purposes, a C_{10} correction factor of-1.5 on Danys' recommended average unridged rough ice value has been applied for the ridged ice expected in all three scenario locations.

3.2.2 Wave Forces

Structures envisaged as offshore mooring and loading terminals, storage facilities or nearshore terminals in the Bering Sea environment range in size and shape from highly compliant single point mooring systems to massive, rigid gravity-type storage structures. The methods and analytical procedures appropriate for wave force determination are highly structure dependent and vary in design importance among the many feasible concepts and the three scenario locations.

Closed-form solutions do not exist for the calculation of wave forces on unusually shaped, large volume structures. Digital computers are extensively utilized in state-of-the-art numerical solutions for boundary value problems in modified potential flow theory, more commonly called diffraction theory. The procedure often requires a time stepped solution for the velocity potential of the flow around the structure, obtained at. any one instant in time by integral equation methods generally based on Green's theorem. The intended result of such a three-dimensional sink-source analysis for an offshore structure is to obtain:

- total linear dynamic wave excitation forces and moments,
- linear dynamic pressure distribution over the surface of the structure,
- added mass and damping coefficients of the structure,
- mean non-linear horizontal wave drift forces and moments, and
- linear dynamic motions in six degrees of freedom for the structure.

The wave forces on the various structures proposed in this study have been estimated based on previously published results of model testing and theoretical analyses conducted primarily for existing North Sea loading and storage, gravity-type and compliant structures. In calculating wave forces based on analyses of existing structures, due consideration was given to the effects of the following parameter variations:

- water depth,
- wave height, period, length,
- structure shape, dimensions, volume,
- structure characteristic dimension/wave length relationship, and
- wave height/water depth relationship.

References by Apelt & Macknight (1976), Garrison et al. (1974), Hogben & Standing (1974), Isaacson (1981), Kokkinowrachos & Wilckins (1974), Loken & Olsen (1976), Skjelbreia (1979), and Torum et al . (1974) were used in determining wave forces for large, fixed, rigid structures.

In the less severely ice infested areas of the Central and Southern Bering Sea, greater water depths and lower ice loading favor compliant structures similar to those currently being used as loading and storage facilities in the North Sea. These structures, typically articulated at the base and deriving restoring characteristics from buoyancy and/or catenary chain restraining systems, present additional difficulties for hydrodynamic analysis techniques over those encountered for massive rigid structures. The effects of the non-linear stiffness of the compliant structure and the independent high frequency motions of the moored tanker augment the dynamic and non-linear aspects of the model and enhance the effect of second-order motions and forces throughout the coupled system. Previous model test results and computer program analyses performed for similar system configurations have been employed to establish estimated wave responses for the proposed structures.

3.2.3 Wind Forces

Wind forces on all offshore facilities have been determined in accordance with API RP 2A "Recommended Practice for Planning, Designing and Constructing Fixed Offshore"Platforms" (1982).

3.2.4 Current Forces

Current forces on all offshore facilities have been determined in accordance with API RP 2A (1982).

3.2.5 Seismic Forces

Seismic responses for all offshore facilities have been determined i n accordance with API RP 2A (1982) e The seismic analysis for each structure has been performed only to the point of insuring concept feasibility and global stability on the assumption that detailed results will not significantly affect the cost of the various transportation alternatives and final conclusions of the study.

3.3 CRUDE OIL PRODUCTION PARAMETERS

3.3.1 Crude Oil Properties

The characteristics of the crude oil to be produced, the quantity recoverable, the initial productivity and the optimum rate of recovery all may influence the selection of the optimum transportation system. There is no data available to predict the quality of oil that may be found in the Bering Sea lease sale areas. However, many of the Pacific Margin Tertiary Basin fields produce low sulfur, medium to low gravity (medium to high API number) crudes. The gravity of oil in upper Cook Inlet fields, for example, ranges from 27.7 degrees API to 44 degrees API and sulfur content is generally low.

For purposes of this study, the same crude oil properties are assumed for each base case scenario. The properties are based on typical properties of Cook Inlet crude oil as follows:

-Gravity, specific	0.850
-Gravity, API	35.0
-Pour Point, °C (°F)	-15 (5)
-Viscosity, Saybolt Universal	
@ 25°C (77°F)	52 sec
@ 38°C (100°F)	40 sec
-Gas-Oil Ratio	430
-Sulfur, %	0.05
-Temperature, °C (°F)	68 (155)

The most important crude oil properties to be considered in the design of a transportation system are the pour point, viscosity and sulfur content. The Cook Inlet crude oil pour point, viscosity and sulfur content are quite good for both pipeline and tanker transportation systems. In order to evaluate the effect of a less desirable crude, sensitivity analyses were carried out for a crude with a pour point of 16°C (61°F) and a Saybolt Universal viscosity of 300 seconds at 25°C (77°F) and 200 seconds at 38°C (100°F).

It has been assumed that all associated gas will be utilized for fuel or be reinfected.

3.3.2 Recoverable Reserves and Production Rates

The quantity of recoverable reserves in an offshore oil field is a major factor in the determination of the optimum transportation system for the field. For each of the three scenarios analyzed in this study, the base case consists of an oil field with recoverable reserves of 500 million barrels. For the sensitivity analyses, reservoir sizes of 100 million, 200 million, one billion and two billion barrels have been considered.

Production rates are based on an analogy with expected and actual production rates of seventeen fields recently developed in the

North Sea (National Petroleum Council 1981). The following performance has been assumed for each scenario:

- peak annual rate of 9.1 percent of initial reserves,
- building up of peak rate from production startup is 20 percent in year one and 70 percent in year two,
- peak rate occurs in years three, four and five,
- starting in year six, decline is exponential at 12 percent per year, and
- production ceases at the end of year fifteen.

For purposes of this study, it was found more convenient to use the peak production rate rather than the total recoverable reserves when evaluating the sensitivity of the transportation systems to variations in recoverable reserves. Since the peak production rate is 9.1 percent of reserves per year regardless of the size of the reserves, the reader can readily convert peak production rate to recoverable reserves. Throughout this report, when the term "production rate" is used it refers to the peak production rate, unless stated otherwise.

3.4 SIZE AND COSTS OF TANKERS AND ICEBREAKERS

3.4.1 Selection of Tanker Size

In order to compare an offshore loading system transportation alternative with a pipeline system alternative, the total transportation system, including the tankers, must be included in the evaluation. 'l'he most economic size tanker for a particular trade depends on a number of factors, the most important of which include: length of trade route, time in port, throughput, physical restrictions along the trade route, and terminal limitations. Where a vessel is required to transit ice fields, size and power take on added importance as ice breaking capability is primarily dependent on displacement, power, hull strength and shape.

The optimum size tanker for each transportation alternative of each scenario and for each peak crude oil production rate considered has been determined based on the following criteria:

- a minimum of two tankers will be provided on any route,
- overall costs generally decrease with increasing tanker size,
- the maximum size tanker will not exceed 250,000 DWT,
- the cargo carrying capacity of a tanker is equal to 95% of the deadweight,
- the average speed of a tanker in open water is 15 knots,
- the average speed of a tanker in ice concentration exceeding 4 oktas is 8 knots,
- the turnaround time at each loading or unloading terminal is 24 hours, and
- the minimum tanker cargo size provided will be 25% more

than the calculated theoretical minimum during the ice free period or 10% more than the calculated theoretical minimum during the maximum ice coverage period, whichever is larger.

Thus, the optimum size tanker is the largest size determined from the two following formulas:

$$D = \frac{1.25}{0.95} \times \frac{P \times Rs}{N}$$

$$D = \frac{1.10}{0.95} \times \frac{P \times Rw}{N}$$

where: D = deadweight of optimum size tanker;

P = peak crude oil production rate;

Rs = round trip time during ice free period;

Rw = round trip time during maximum ice coverage period;

N = number of tankers.

3.4.2 Ice-Strengthened Tankers

Tankers servicing an offshore or a nearshore terminal in the Bering Sea must be ice capable. Thus, they will be purpose built and quite different, and more expensive, than tankers presently operating in areas such as the North Sea. In addition, these tankers must be constructed in the U.S. in order to comply with the requirements of the Jones Act which further increases their cost by a factor of approximately two compared with tankers built in Japanese and Korean shipyards,

The degree of ice-strengthening, the power requirements and the optimum configuration vary depending on the extent to which the tanker's route requires it to penetrate the Bering Sea ice cover. For tankers serving the Northern Bering Sea, Class 4 strengthening is required, for the Central Bering Sea, Class 2 and for the Southern Bering Sea, Class 1. The optimum configuration for these tankers must be based on a compromise between the low speed and high horsepower requirements for transiting ice and the high speed and low horsepower requirements for open water. The estimated tanker dimensions are shown in Figure 3-12 for Class 4, Figure 3-13 for Class 2 and Figure 3-14 for Class 1. The displacement and horsepower are shown in Figures 3-15 through 3-17 and the capital and operating costs are shown in Figures 3-18 through 3-20. The dimensions, displacement, horsepower' and costs indicated have been compiled and developed from a number of published reports (McMullen 1980, Global Marine 1977, National Petroleum Council 1981, Voelker et al. 1981a) and should be considered preliminary. The maximum size of the tankers has been limited to 250,000 DWT so as not to restrict too severely the potential receiving terminal locations. For tankers traveling to the Northern Bering Sea, the loaded draft has been limited to 21 m (69 ft) to enable them to traverse the most direct route. Capital costs assume U.S. construction and include estimated construction and financing costs. Operating costs include 32 man crew, maintenance, insurance, other fixed costs and fuel consumption.

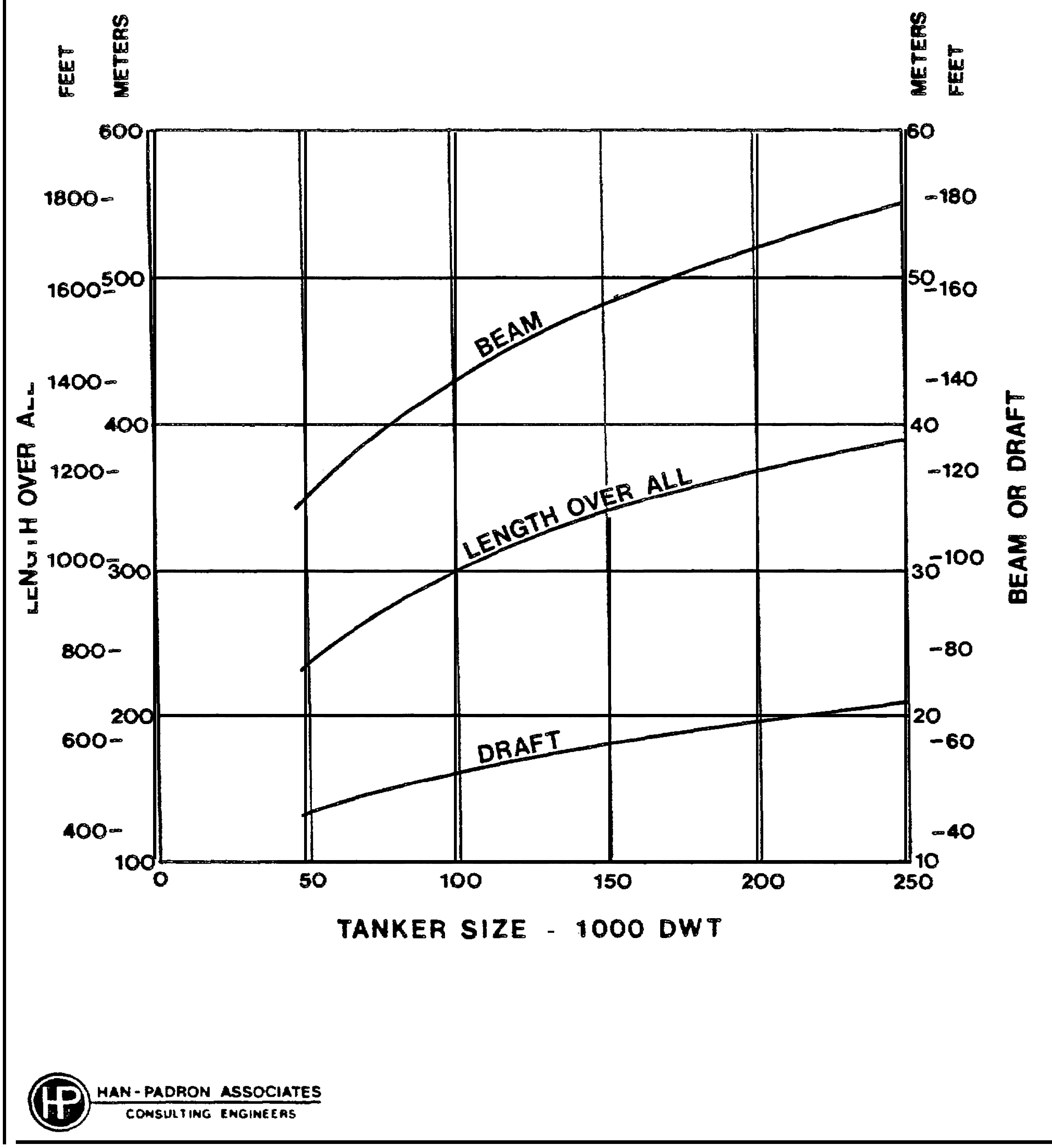

Figure 3-12. Dimensions of Class 4 ice-strengthened tankers.

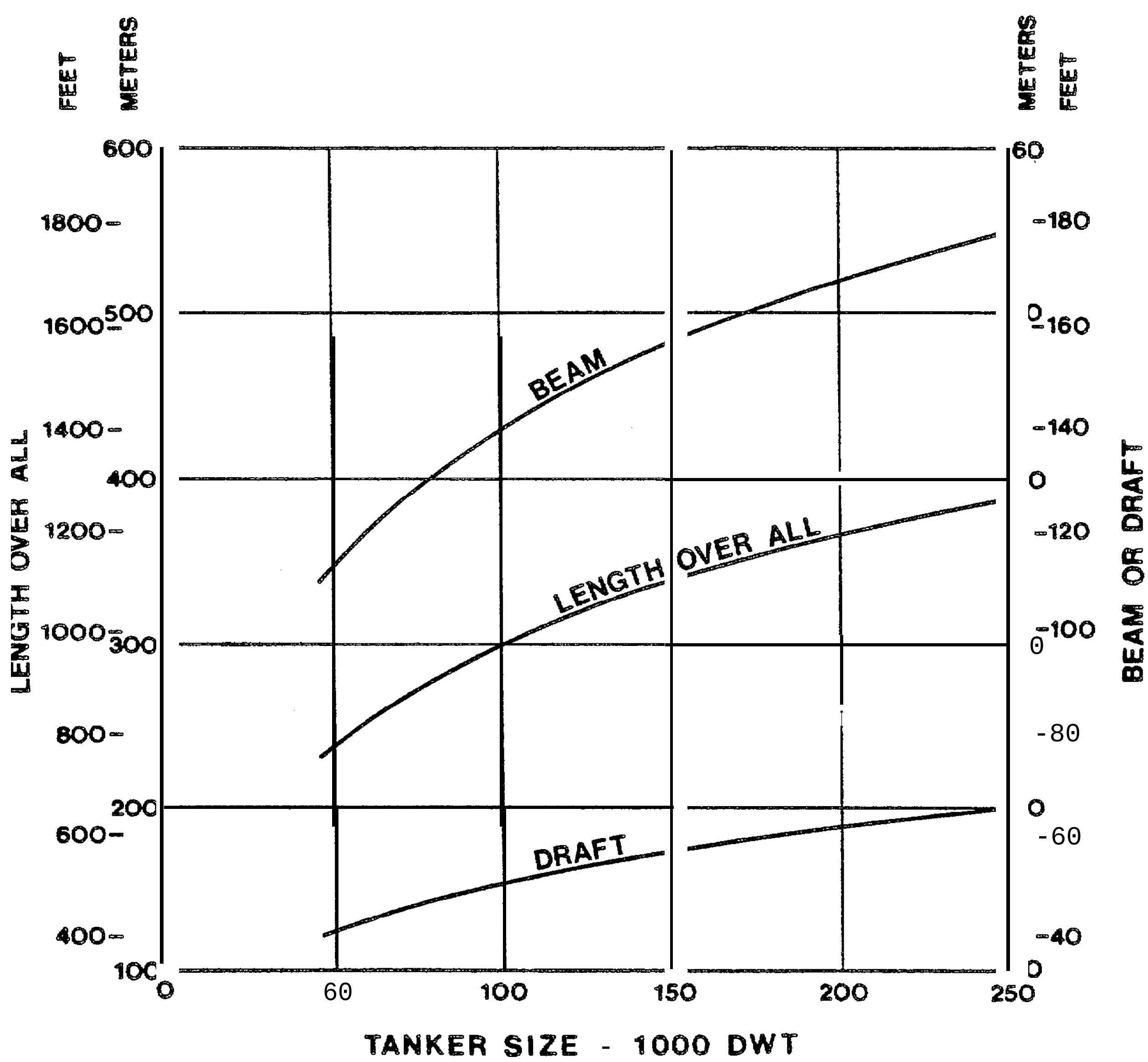

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Figure 3-13. Dimensions of Class 2 ice-strengthened tankers.

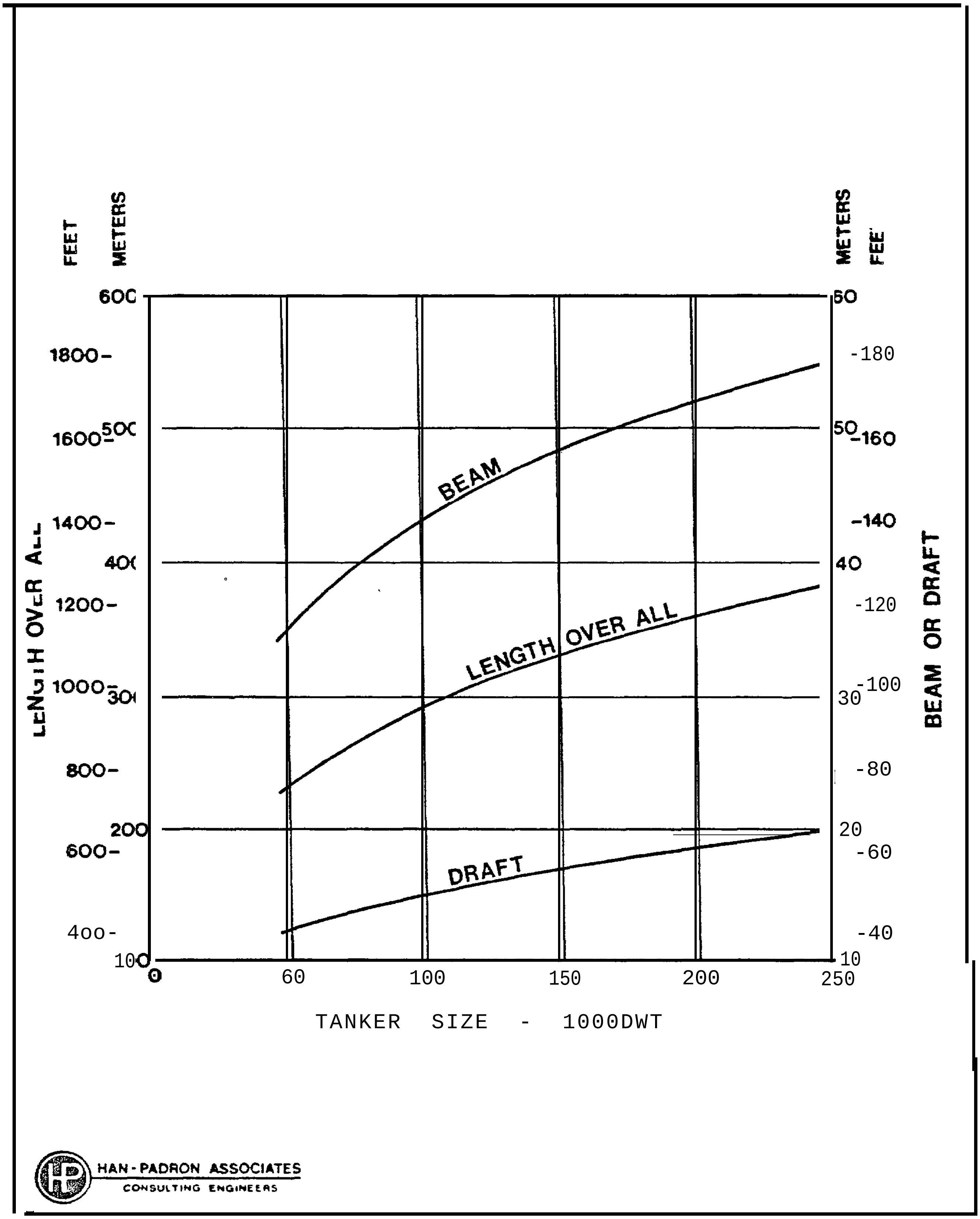

Figure 3-14. Dimensions of Class 1 ice-strengthened tankers.

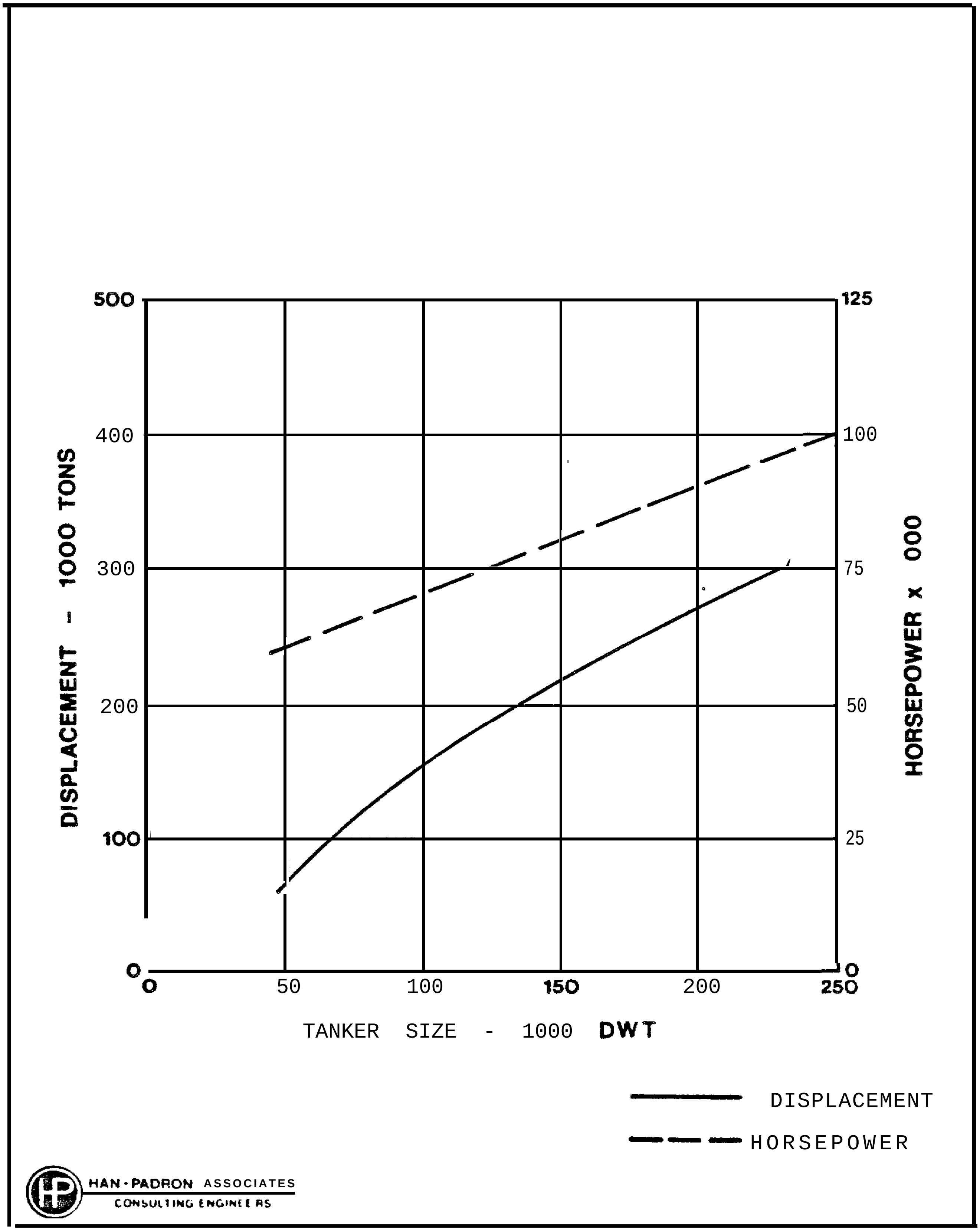

Figure 3-15. Displacement and horsepower of Class 4 ice-strengthened tankers.

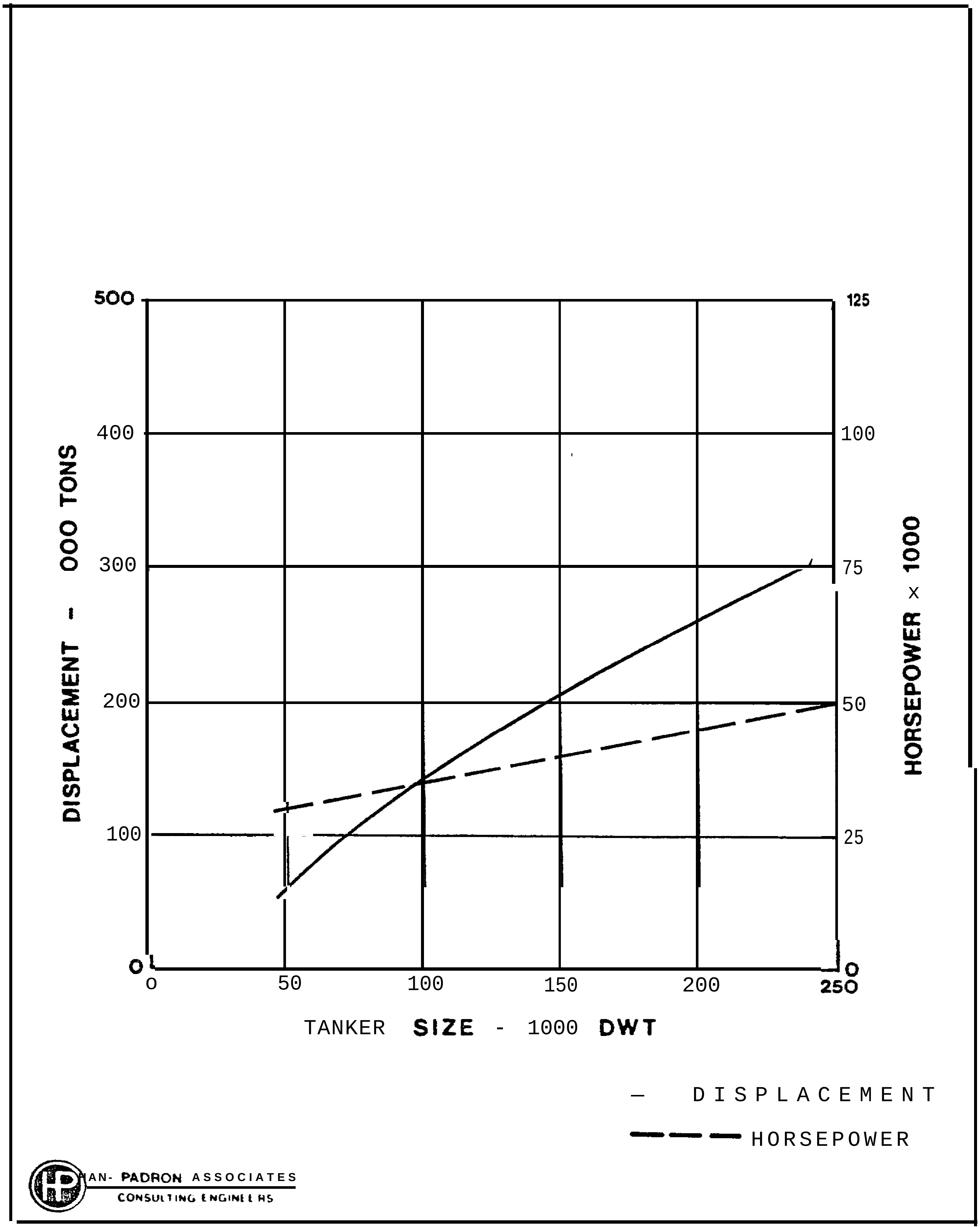

Figure 3-16. Displacement and horsepower of Class 2 ice-strengthened tankers.

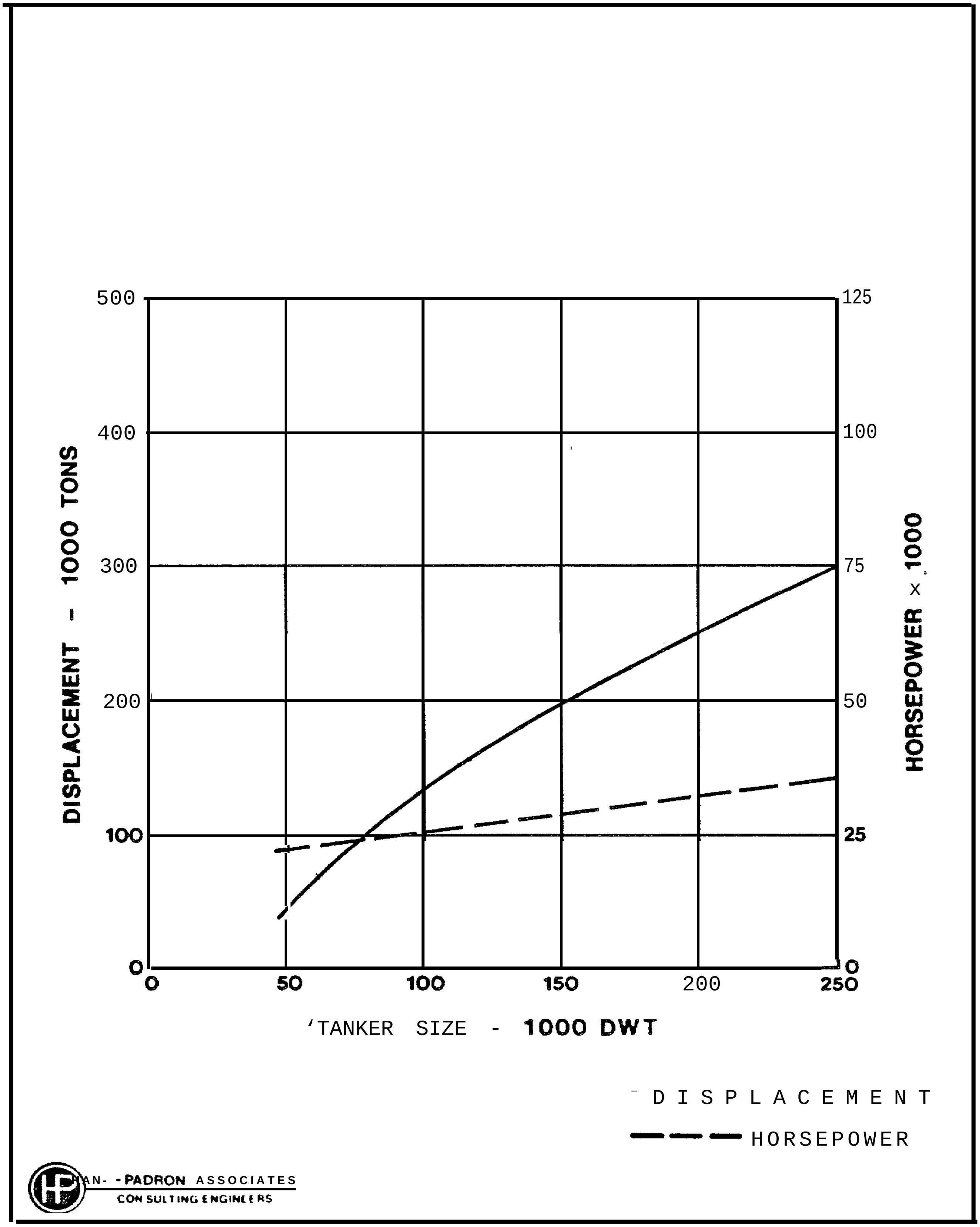

Figure 3-17. Displacement and horsepower of Class 1 ice-strengthened tankers.

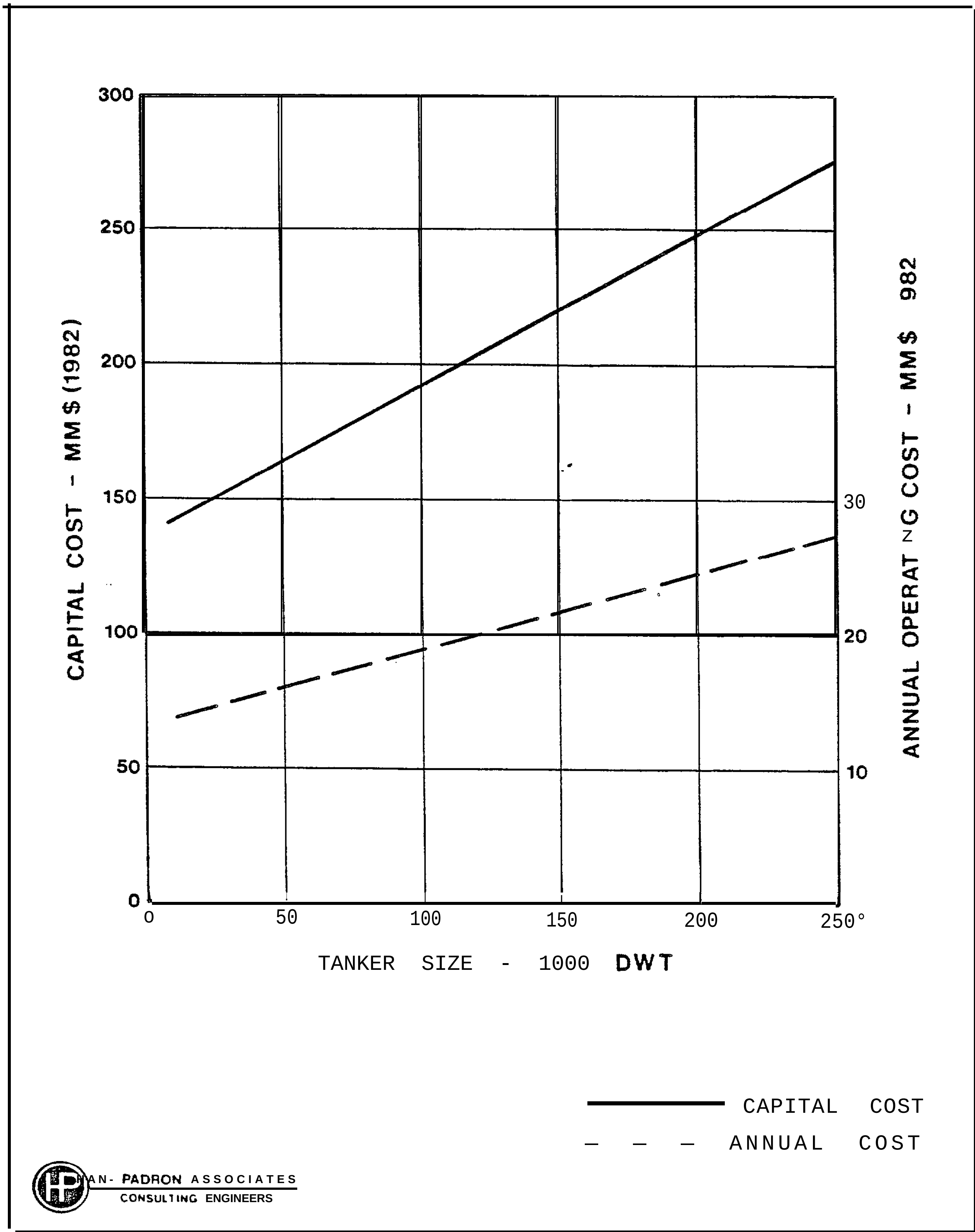

Figure 3-18. Class 4 ice-strengthened tanker capital and annual costs versus tanker size.

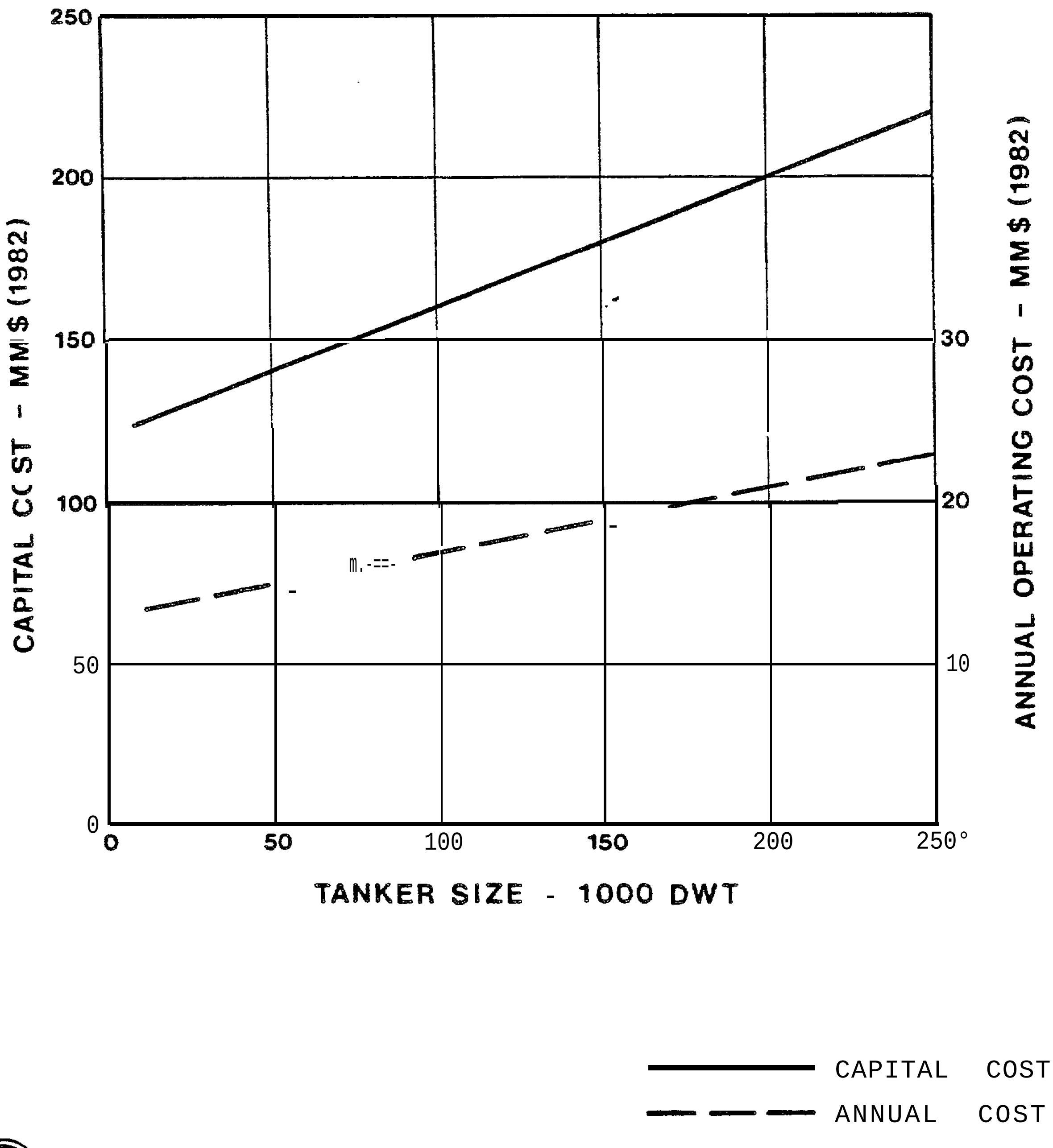

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Figure 3-19. Class 2 ice-strengthened tanker capital and annual costs versus tanker size.

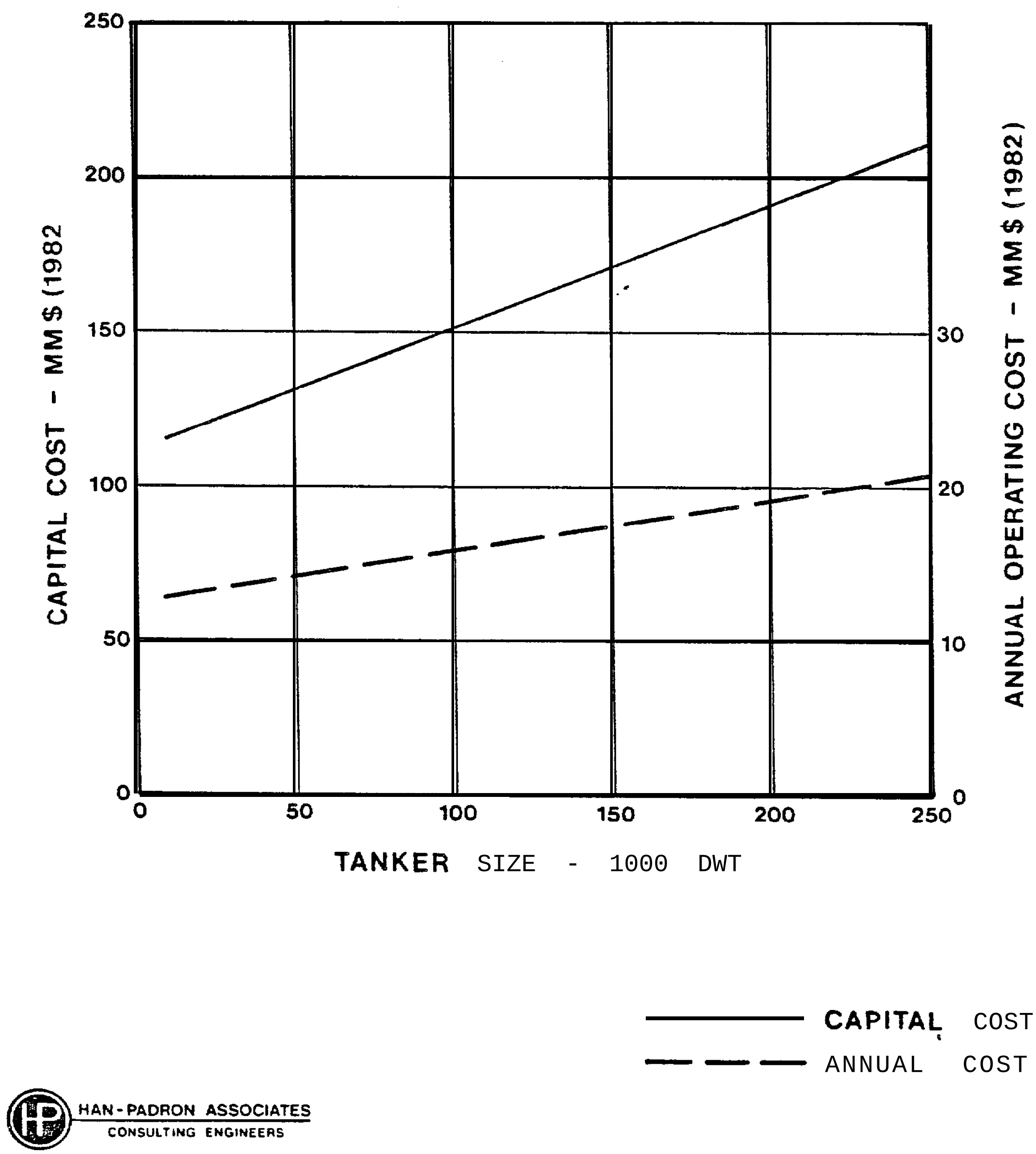

Figure 3-20. Class 1 ice-strengthened tanker capital and annual costs versus tanker size.

It has been assumed that the tankers will be sufficiently maneuverable to approach an offshore mooring unassisted under most circumstances. During heavy ice conditions a lead will usually be created by the mooring structure as the ice flows past and this lead will aid in guiding the tanker to the mooring. During especially severe conditions an icebreaker will be available to assist in the tanker approach and mooring operations.

3.4.3 Conventional Tankers

Conventional tankers will be utilized on the route between an Alaska Peninsula or Cook Inlet nearshore loading or transshipment terminal and the U.S. West Coast. As for the ice-strengthened tankers, these tankers must be U.S. built. Federal regulation 33 CFR Part 157.09 requires that new tankers have segregated ballast tanks in protective locations. Therefore, no ballast water treatment facility will be required at the loading terminal. The conventional tanker size has been limited to 250,000 DWT so as not to restrict too severely the potential receiving terminal locations. The basic dimensions of conventional tankers are shown in Figure 3-21.

The capital and operating costs of conventional tankers with segregated ballast tanks are shown in Figure 3-22. These costs are based on new building in U.S. shipyards. They are also based on 1982 dollars and the assumption that shipbuilding costs will be at a

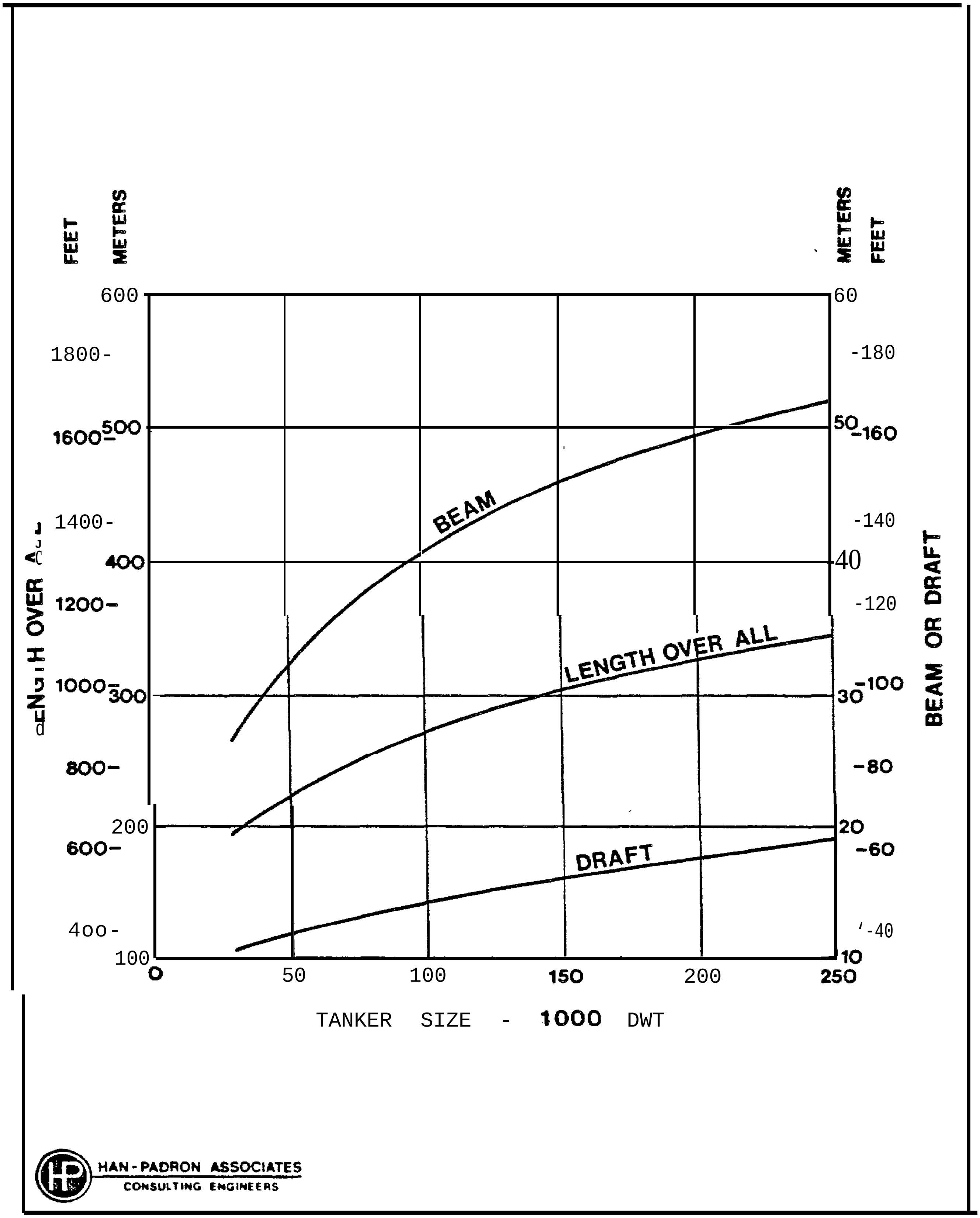

Figure 3-21. Dimensions of conventional tankers.

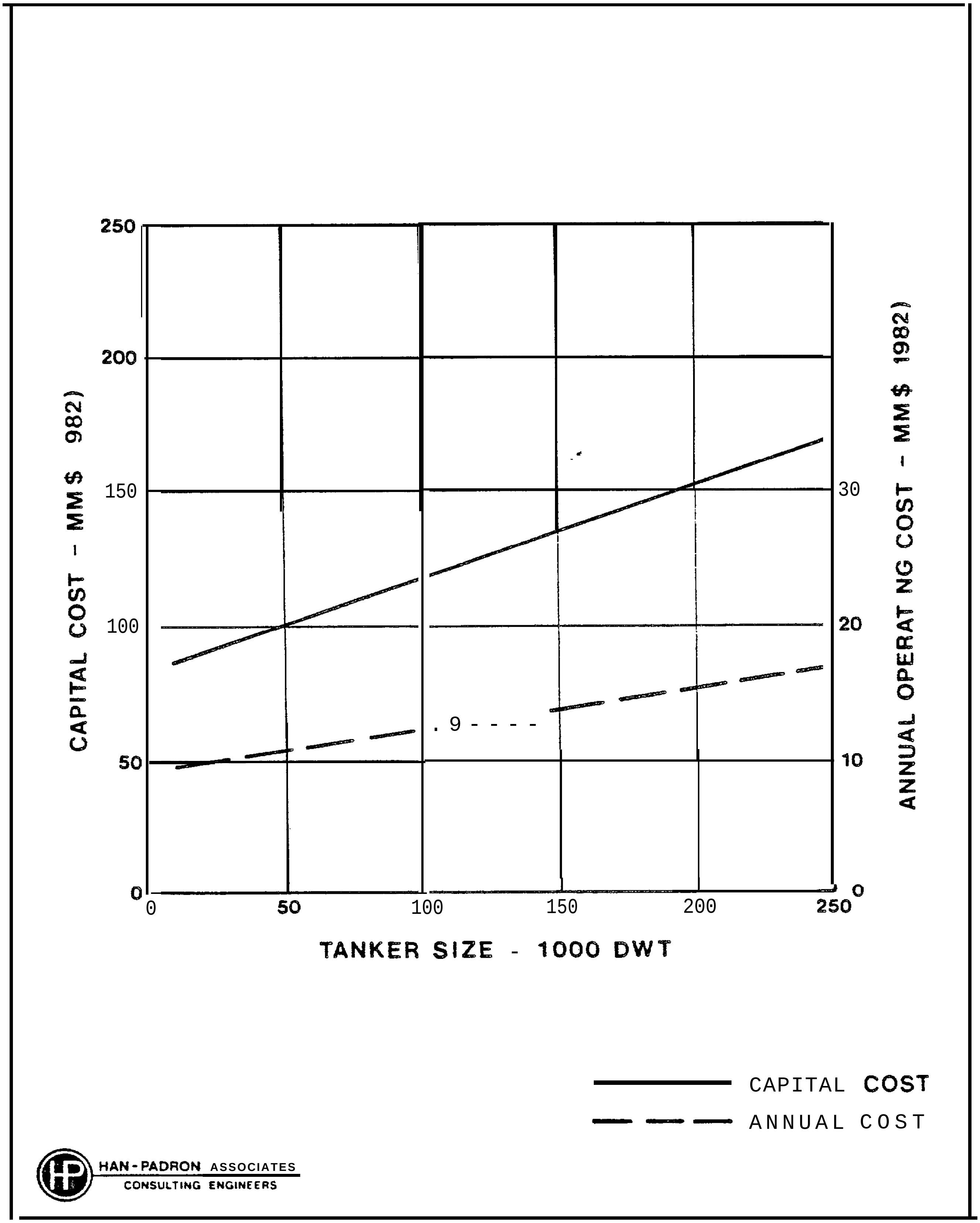

Figure 3-22. Conventional tanker capital and annual costs versus tanker size.

relatively high level , similar to the level which existed in 1980 and 1981. Operating costs include 30 man crew, maintenance, insurance, other fixed costs and fuel consumption.

3.4.4 Icebreakers

All tankers will be sufficiently powered to have but minor problems completing passage to the offshore or nearshore loading terminals. However, due to the size of the vessels and the surrounding, confining ice field, tanker maneuverability will be limited and the most ice-capable tanker could be slowed and eventually stopped by a heavy concentration of large ridges. Icebreaker assistance will be required to provide support for the following operations:

- escort operations in areas of extreme ice concentrations,
- clearing terminals and maintaining approaches to terminals,
- maneuvering tankers during approach and departure from terminals and mooring assistance,
- breakout of beset tankers,
- delivery of personnel and supplies between terminals, tankers, and platforms,
- pollution control,
- deflection of ice to prevent emergency breakaway or disruptions to the loading process, and

- emergency services such as fire fighting and search and rescue.

Since these icebreakers must be highly maneuverable in heavy ice conditions and capable of moving quite rapidly through the ice field, they cannot be designed based entirely on ice thickness but must include a sufficient allowance for negotiating pressure ridges. In order to develop cost data for Icebreaker support. vessels, it has been assumed that they will be designed to be one Class higher than the Class of the tankers serving the area and with an estimated shaft horsepower as indicated in Figure 3-23. Estimated capital and operating cost data for these vessels is given in Figure 3-24. These figures are derived from several published reports and articles (Voelker et al. 1981a, Global Marine 1977, National Petroleum Council 1981, McMullen 1980) and should be considered preliminary. Capital costs are based on the assumption that these vessels will be constructed in U.S. shipyards, increasing their cost by a factor of approximately 1.5 compared with construction in Japanese or Korean shipyards. Operating costs include 25 man crew, maintenance, insurance, other fixed costs and fuel consumption.

3.5 TERMINAL LIESIGN PHILOSOPHY AND COST'S

A marine terminal, as used throughout this report, includes tanker loading/unloading facilities, crude oil storage, marine pipelines connecting the storage facilities to the tanker loading/

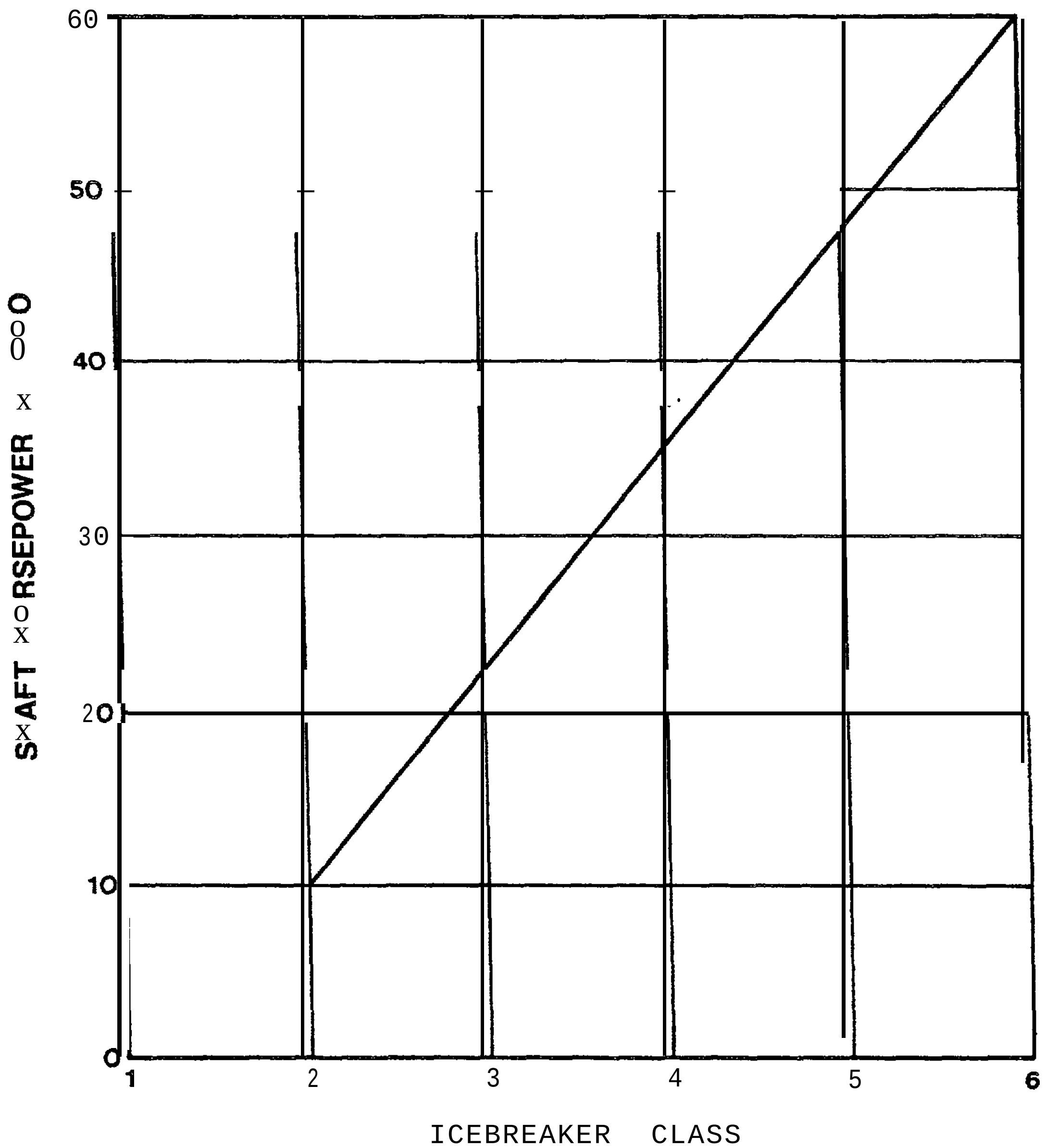

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Figure 3-23. Icebreaker shaft horsepower versus Class.

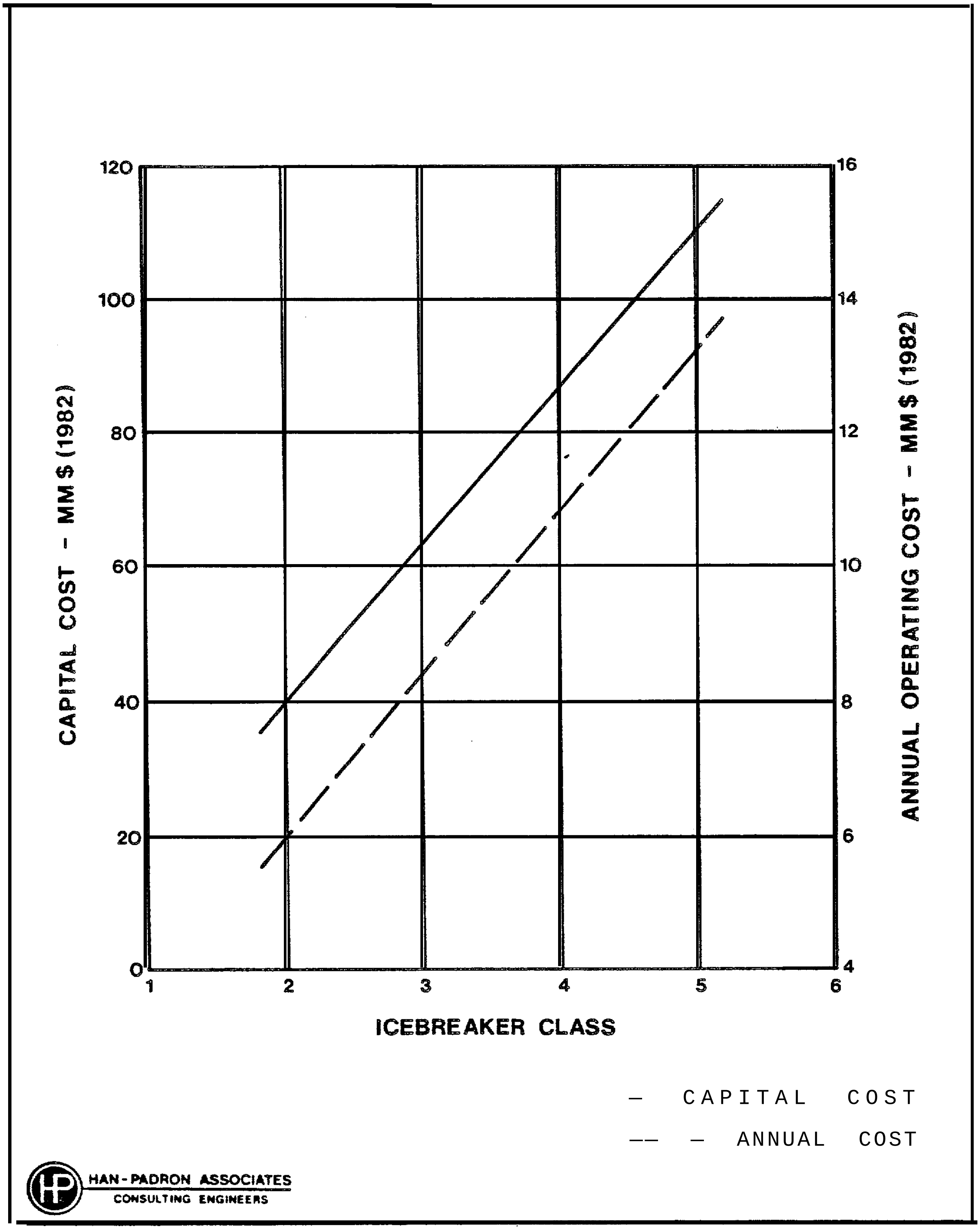

Figure 3-24. Icebreaker capital and annual costs versus Class.

unloading facilities and production platform, pumping/metering/piping facilities, living quarters for operating crew, power plant, communication facilities and all ancillary facilities required for a complete tanker loading/unloading terminal. In general, three types of terminals are considered, offshore terminals, nearshore terminals and transshipment terminals.

An offshore terminal is defined as a terminal where all facilities, including crude oil storage and tanker loading facilities, are located near the production platform (usually within 1.5 km (1 mi) of the production platform). A nearshore terminal is defined 'as a receiving terminal for a crude oil pipeline from the production platform, with onshore storage tanks and a tanker loading facility located as close to the storage tanks as water depths permit. A transshipment terminal is defined as a terminal located in ice-free waters, with facilities for unloading ice-strengthened tankers, storing the crude oil in onshore storage tanks and loading conventional tankers.

3.5.1 Design Philosophy

Since each terminal is assumed to serve only a single oil field and throughput rates are consequently relatively low, the preliminary design for each terminal considered in this study is based on providing the minimum facilities necessary for it to function properly. All components will be prefabricated to the greatest extent possible and the terminal will be operated in a manner similar to an offshore production platform in a remote location. Access to the terminal for personnel and supplies will be by boat or helicopter from the supply base established for the drilling/production operations. Crews will work 12 hour shifts and will be rotated on the same basis as production platform crews, i.e., a shift factor of 2 and a rotation factor of 2.

All terminals will be supported by two vessels. For terminals in locations subject to ice, the vessels will be icebreakers with characteristics as described in Section 3.4.4 and will provide the following support:

- escort operations in areas of extreme ice concentrations,
- clearing tanker mooring facilities and maintaining approaches to the terminal,
- maneuvering tankers during approach and departure from the terminal and mooring assistance,
- breakout of beset tankers,
- delivery of personnel and supplies between the terminal, tankers, and platforms,
- pollution control,
- deflection of ice to prevent emergency breakaway or disruptions to the loading process, and
- emergency services such as fire fighting and search and rescue.

For terminals in ice-free areas, the vessels will be large launches with a 5 man crew and will provide the following support:

- mooring line and hose handling and mooring assistance,
- delivery of personnel and supplies between the terminal and tankers,
- pollution control, and
- emergency services such as fire fighting and search and rescue.

a) Offshore Terminal

The offshore terminal for each of the three scenarios is different and they are described in detail in Chapters 4, 5 and 6 for Scenarios 1, 2 and 3, respectively. However, there are several principles, as listed below, that have been applied in the preliminary design of each offshore terminal.

- The offshore loading system will be a single point mooring to permit the tanker to "weathervane", thus minimizing forces acting on the system.
- Mooring hawsers will be kept out of the water when not in use.
- Three types of tanker loading systems, mounted on a long, freely rotating boom on top of the mooring

structure, are considered suitable: articulated loading arms, reeled hoses and suspended hoses. A more detailed evaluation is required to establish the best system for a particular scenario.

- All loading systems will be kept out of the water at all times.
- All facilities that are not readily movable are designed to withstand the maximum 100 year storm or ice event.
- All facilities that are readily movable (tankers) are designed to withstand the maximum 1 year ice event.
- The minimum clear distance between a mooring and another structure is 1.6 km (1 mi).
- The pumping/metering/piping system is sized to load all tankers in 12 hours.
- Since all tankers serving an offshore terminal will be ice-strengthened and have segregated ballast, no ballast water treatment facilities are provided.

Since there are no existing offshore loading systems that are suitable for the ice conditions of the Bering Sea, new concepts and modifications to existing concepts were developed and evaluated. The optimum offshore loading system for each scenario was based on consideration of the following factors:

- ability to resist ice, wave, wind, current and seismic forces,

- mooring system reliability and ease of mooring operations,
- manning requirements and personnel safety,
- adaptability to variations in water depth,
- adaptability to variations in soil conditions,
- utilization of existing technology, as opposed to the development of new, unproven technology,
- icebreaker support requirements,
- potential damage to the environment, and
- capital, operating and maintenance costs.

An offshore terminal tanker berth without integral storage will have a 10 man crew and an estimated annual operating cost of $4.0 million. An offshore terminal tanker berth with integral storage will have a 40 man crew and an estimated annual operating cost of $8.0 million plus 2.5 to 3 percent of the capital cost.

A description of the tanker loading pipeline systems and their capital costs is given in Section 3.5.5.

b) Nearshore Terminal

Each scenario considered contains several transportation alternatives that include a nearshore loading terminal. As for the offshore terminals, the nearshore terminal for each scenario is different and they are described in detail in Chapters 4, 5 and 6.

Some nearshore terminals are subject to ice and others are in ice-free locations. However, there are a number of principles that have been applied in the preliminary design of each nearshore terminal.

- The tanker mooring system will be a single point mooring (except at a terminal in Cook Inlet where a fixed berth will be provided),
- The location of the terminal (other than in Balboa Bay or Cook Inlet) is at a shore location that minimizes the length of pipeline required from the production platform, with some slight. variations to locate where deep water is closest to shore. No evaluation of the nearshore terminal site has been conducted.
- The tanker mooring is located as close to shore as the designated tanker size and water depth permit, allowing for adequate tanker maneuvering space.
- The pumping/metering/piping system is sized to load all tankers in 12 hours.
- No ballast water treatment facilities are required because all tankers will have segregated ballast tanks.

A nearshore terminal tanker berth, other than at Balboa Bay and Cook Inlet, will have a 10 man crew and an estimated annual operating cost of $4.0 million.

A description of the crude oil storage and other facilities provided at the terminal and their capital and annual operating costs is given in Section 3.5.4. A description of the tanker loading pipeline systems and their capital costs is given in Section 3.5.5.

c) Transshipment Terminal

Each scenario considered contains transportation alternatives that include a transshipment terminal. The purpose of the transshipment terminal is to transfer crude oil from relatively expensive ice-strengthened tankers to relatively inexpensive conventional tankers for delivery to a receiving terminal on the U.S. West Coast. Balboa Bay, on the south coast of the Alaska Peninsula (see Figure 3-25), has been selected for purposes of this study as the transshipment terminal site for all scenarios because it is well protected and has deep water close to shore. However, no evaluation of potential transshipment terminal sites has been carried out and other sites on the Alaska Peninsula or in the Aleutian Islands may be more suitable. The selection of another such site would not significantly affect the conclusions of this study.

The tanker berths for the transshipment terminal will be conventional single point moorings of the catenary anchor leg mooring (CALM) type, as illustrated in Figure 3-26, or single anchor leg mooring (SALM) type, as illustrated in Figure 3-27. For alternatives that require two berths, a sea island type system may prove

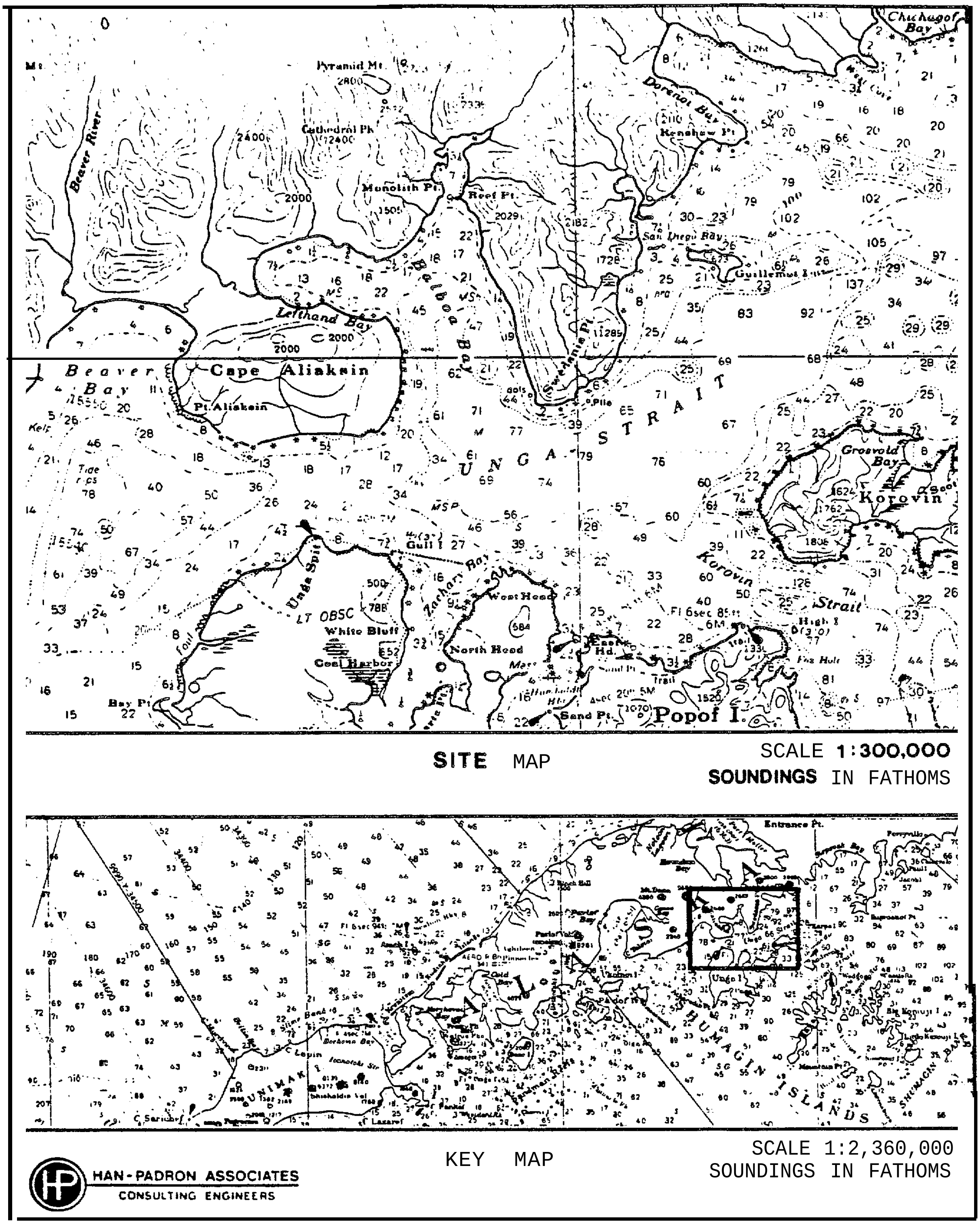

Figure 3-25. Location of **Balboa** Bay transshipment terminal.

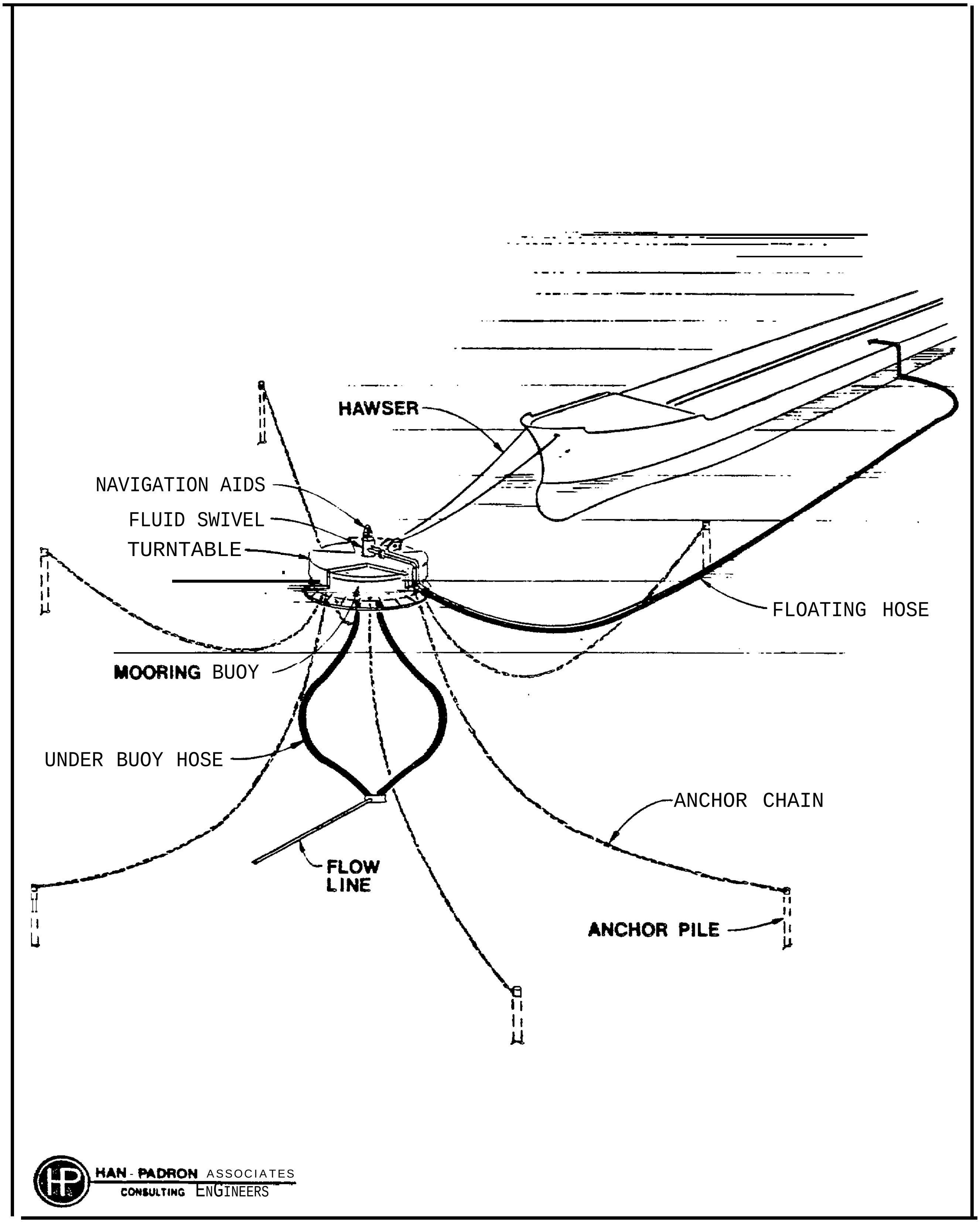

Figure 3-26. Catenary anchor leg mooring (CALM).

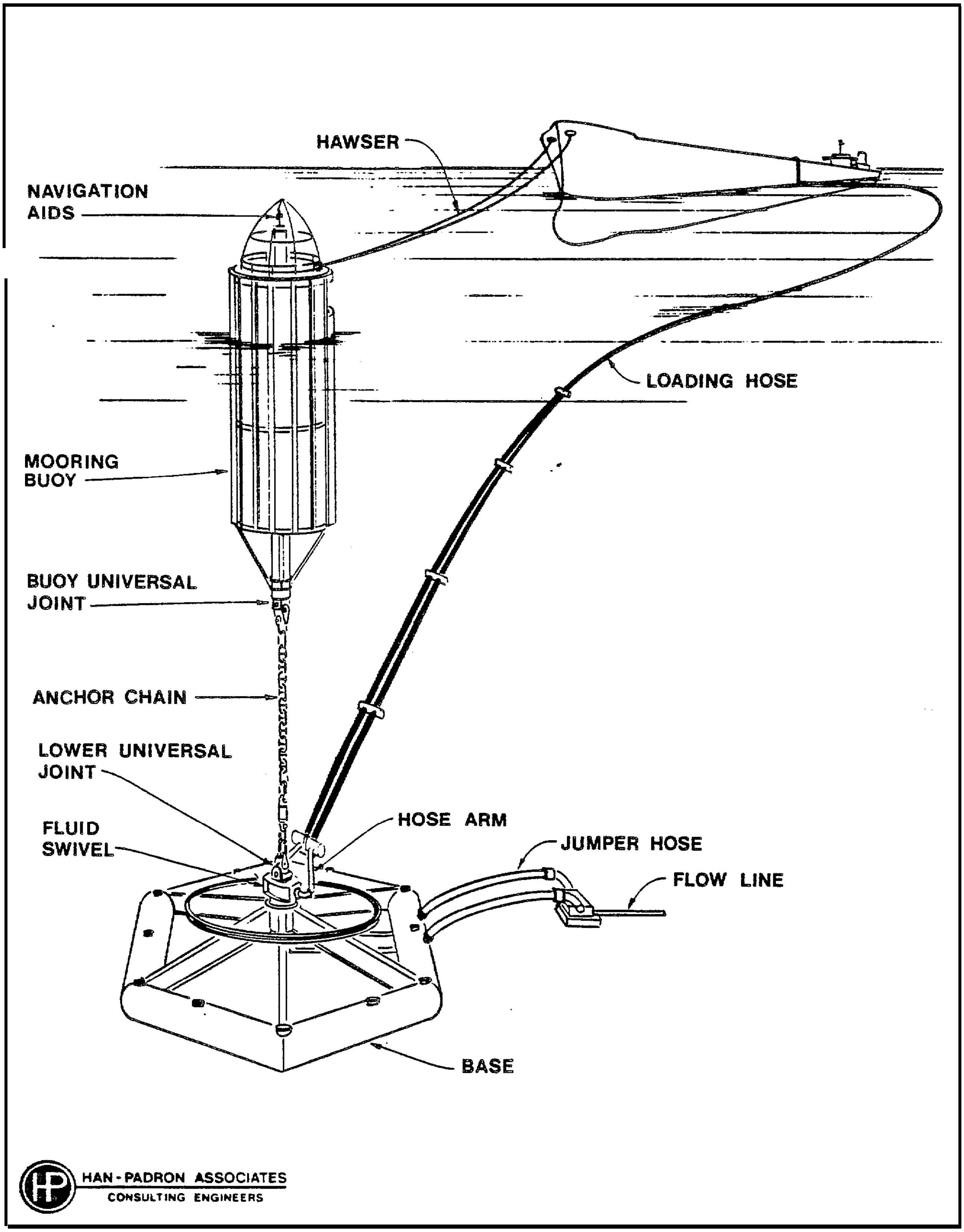

Figure 3-27. Single anchor leg mooring (SALM).

preferable to two single point moorings, but for purposes of this study, either system will provide the same results. The installed cost of either a CALM or SALM, for the environmental conditions and range of tanker sizes considered, is approximately $30 million.

No manpower is required for the tanker berths but two launches are required. Each launch will have a 5 man crew. The total annual operating cost for a transshipment terminal berth is estimated to be $4.0 million, including the launches.

A description of the crude oil storage and other facilities provided at the terminal and their capital and annual operating costs is given in Section 3.5.4. A description of the tanker loading/unloading pipeline systems and their capital costs is given in Section 3.5.5.

3.5.2 Operating Criteria

The percentage of time that a marine terminal is unavailable to moor or load/unload tankers is an important consideration in the evaluation of a crude oil transportation system. The terminal may be unavailable because of severe weather (weather downtime) or maintenance/repair operations (maintenance downtime). The total average number of days per year that a berth is available for tanker loading divided by 365, expressed as a percent, is referred to as the "berth availability rate."

For each type of marine terminal considered and for each type of mooring system considered, a berth availability rate has been established for use in the overall analysis of each transportation alternative. The berth availability rate was established based on the environmental criteria listed in Chapters 4, 5 and 6 for each scenario and is presented in those chapters for each case of each scenario. The following criteria were used to establish berth availability values.

- All tankers and mooring facilities will be equipped with the most modern navigation systems and mooring operations will take place during periods of reduced visibility (fog) and at night.
- All tankers will be equipped with a bow manifold and a bow control house for mooring operations.
- Ice conditions will not prevent mooring and loading operations. Icebreaker assistance may be required to achieve this.
- Mooring operations at a rigid tower or articulated tower type offshore loading system will take place in seas with a significant wave height up to 4.0 m (13 ft) and loading operations will continue in seas with a significant wave height up to 5.5 m (18 ft).
- Mooring operations at a floating storage vessel, based on tandem mooring, will take place in seas with a

significant wave height up to 3.0 m (10 ft) and loading operations will continue in seas with a significant wave height up to 4.5 m (15 ft).

- Mooring operations at a conventional CALM or SALM will take place in seas with a significant wave height up to 2.5 m (8 ft.) and loading operations will continue in seas with a significant wave height up to 4 m (13 ft).
- Unscheduled maintenance at conventional CALM or SALM type offshore loading systems causes 10 percent maintenance downtime while at all other types of single point mooring berths considered it causes 5 percent maintenance downtime. (Scheduled maintenance is assumed not to interfere with tanker operations.)

3.5.3 Number of Tanker Berths

The optimum number of tanker berths to be provided at a terminal depends on:

- the size of ships using the terminal,
- the required berth occupancy time per ship,
- queuing delays as a function of the number of berths,
- frequency and duration of berth closures due to weather conditions,
- the cost of ship waiting time,
- the capital cost for new berths, and
- the annual operating cost for new berths.

Queuing delays at a terminal are caused by ships arriving at uneven time intervals and having to wait, on occasion, for a previous ship to clear the berth. Experience at most marine terminals has shown that ships will arrive in a random pattern. At the terminals considered for this study, a dedicated fleet of carefully scheduled tankers will be calling. However, due to the relatively long travel distances for most cases, the unpredictable weather conditions and particularly the unpredictable speed of tankers through the variable ice cover, it is reasonable to assume, for preliminary design purposes, that the tankers will arrive at each terminal in a random pattern.

Mathematical analyses have been developed (based on the assumption of a random arrival pattern) which present the average waiting time of a vessel arriving at a terminal as a function of the berth occupancy rate and number of berths. The berth occupancy rate, in percent of total berth time, may be computed as follows:

$$\text{Berth Occupancy Rate} = \frac{N \times T \times 100}{B \times 365 \times 24 \times A} = \frac{.0114 \times N \times T}{B \times A}$$

where: N = number of ship arrivals per year;

T = average berth occupancy time per ship, in hours;

B = number of available berths; and

A = berth availability rate (as defined in Section 3.5.2).

Berth occupancy time, T, is defined as the length of time required for the ship to approach and moor, load or discharge its cargo, complete all documentation requirements and depart the berth area. In the absence of actual performance records, it has been assumed that the average time required for the various operations of mooring, inspection, cargo transfer system connection and disconnection, completion of documentation, and unmooring, is 8 hours. The loading or unloading time depends on the design rate for the facility which for this study has been sized to complete loading/unloading operations in 12 hours. Allowing for unscheduled delays, a berth occupancy time of 24 hours has been assumed.

Figure 3-28 gives a graphic presentation of the theoretical ratio of average tanker waiting time to average berth occupancy time versus berth occupancy rate, for various numbers of berths, based on a random arrival pattern and uniform service time. With this information, the total ship waiting time, and thus its cost, can be calculated for various numbers of berths. This cost can then be added to the annualized cost of constructing and operating the corresponding numbers of berths and the optimum number of berths selected.

A detailed evaluation of the optimum number of berths at each terminal is not warranted at this preliminary evaluation stage.

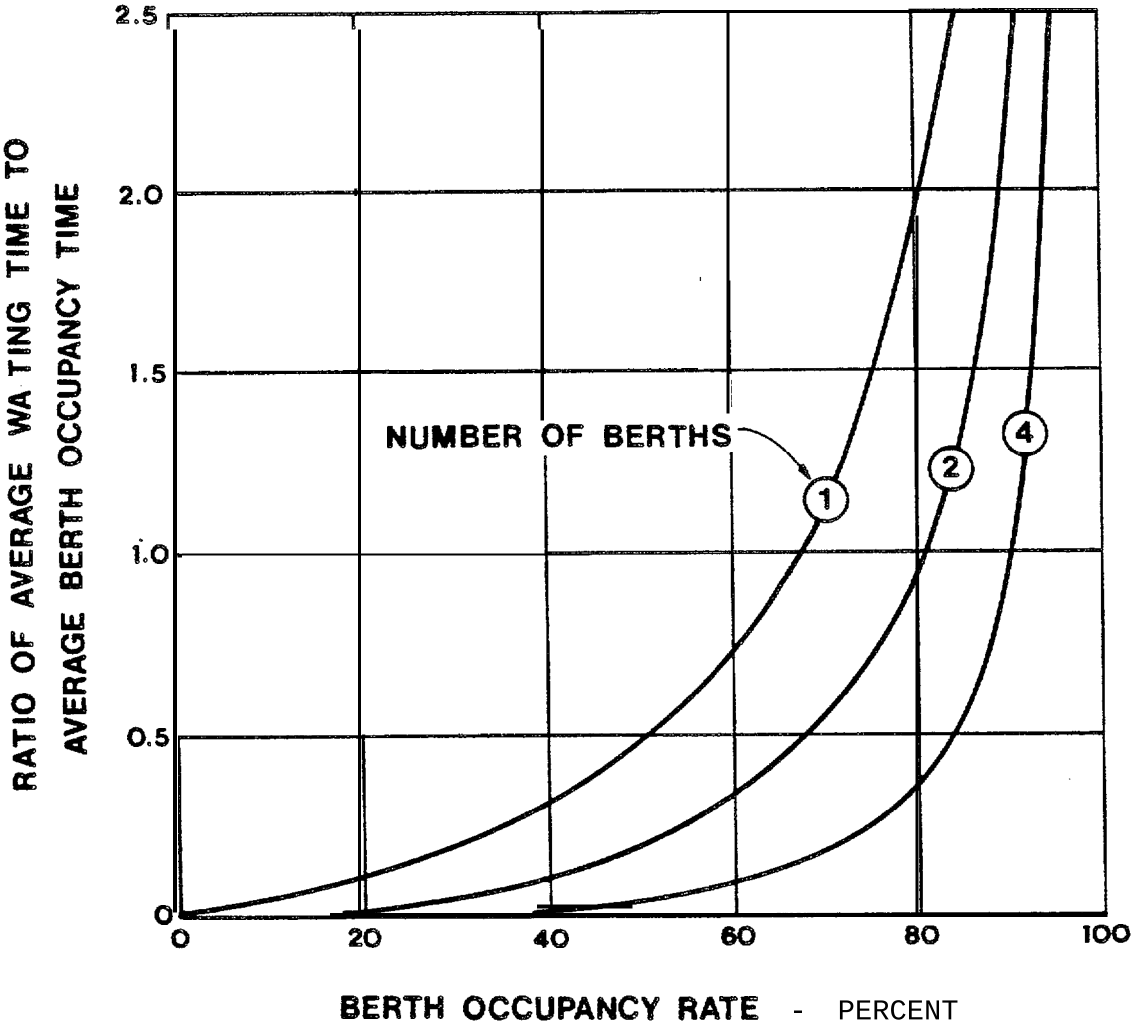

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Figure 3-28. Average tanker waiting time versus berth occupancy rate.

Based on operating experience at existing terminals, a berth occupancy rate of 40 percent was selected as the maximum economical rate for a single berth terminal subject to ice conditions. For a two berth terminal under the same conditions, the selected maximum economical occupancy rate is 60 percent. For terminals in ice-free locations, where the cost of the mooring facility is considerably lower, a maximum berth occupancy rate of 35 percent has been used for a single berth terminal and 55 percent for a two berth terminal, In no case considered in this study are more than two berths required.

3.5.4 Crude Oil Storage Facilities

The volume of crude oil storage capacity provided at a terminal, either offshore, nearshore or transshipment terminal, has a significant effect on the cost of the terminal, especially for offshore terminals. The determination of the optimum storage capacity for any particular scenario requires a thorough evaluation of the incremental cost of storage capacity, the cost of tanker delay time, the incremental cost of increased tanker size, the effect (cost) of reduced production rate or production shut-in, and a number of other factors. Based on extensive experience at other terminals, it has been assumed that the volume of storage required to virtually eliminate reductions in production rate and to ensure that tankers will not be required to wait due to a lack of crude oil, is close to the optimum storage capacity.

An evaluation of the duration of terminal closure due to severe weather was carried out for each scenario and for each type of loading system considered. The evaluation was based on wind duration records available for each area (Brewer et al. 1977). The maximum duration of 99 percent of winds exceeding 10 m per sec (20 knots) was selected as the maximum weather closure period in each case.

The required storage capacity was calculated on the assumption that the maximum weather closure would occur at a time when a quantity of crude oil equal to the capacity of one tanker is in storage. Thus, the storage capacity required is calculated as follows:

$$S = (0.95 \times B \times DWT) + (P \times C)$$

where: S = required storage capacity, in barrels;

B = number of barrels of oil per ton (7.5 for oil with a specific gravity of 0.85);

DWT = size of tanker, in dead weight tons;

P = peak crude oil production rate, in barrels per day; and

C = duration of maximum weather closure, in days.

It should be noted that the storage capacity calculated by the above formula has been utilized for the analyses carried out for this study but is not recommended as being the optimum storage capacity.

Such a recommendation could only be made after a thorough analysis of a particular scenario and the gathering of more reliable data on the expected duration of weather closures.

The concept, details and costs for offshore storage facilities depend on the particular scenario parameters. A discussion of offshore storage facilities for each scenario is contained in Chapters 4, 5 and 6.

The arrangements and unit costs for onshore storage capacity are assumed to be the same for all scenarios and for both nearshore and transshipment terminals. The proposed layout of the tank farm is based on utilizing 500,000 barrel, steel, floating-roof tanks. The tanks are 76 m (250 ft) diameter by 18 m (60 ft) high and are spaced 215 m (700 ft) on centers. Bund walls 2 m (6 ft) high are provided around each tank to retain the full volume of the tank should it rupture. It is assumed that the first bund wall is located approximately 300 m (1000 ft) from the shoreline. All other facilities required for the tank farm, including power generation, living quarters, administration and maintenance buildings, fire protection, water supply, waste water treatment, supplies and fuel storage, helipad, etc., are located between the tanks and the sea. Figure 3-29 shows a typical layout of the tank farm.

The estimated land area required for the storage facilities is shown in Figure 3-30 as a function of crude oil storage capacity.

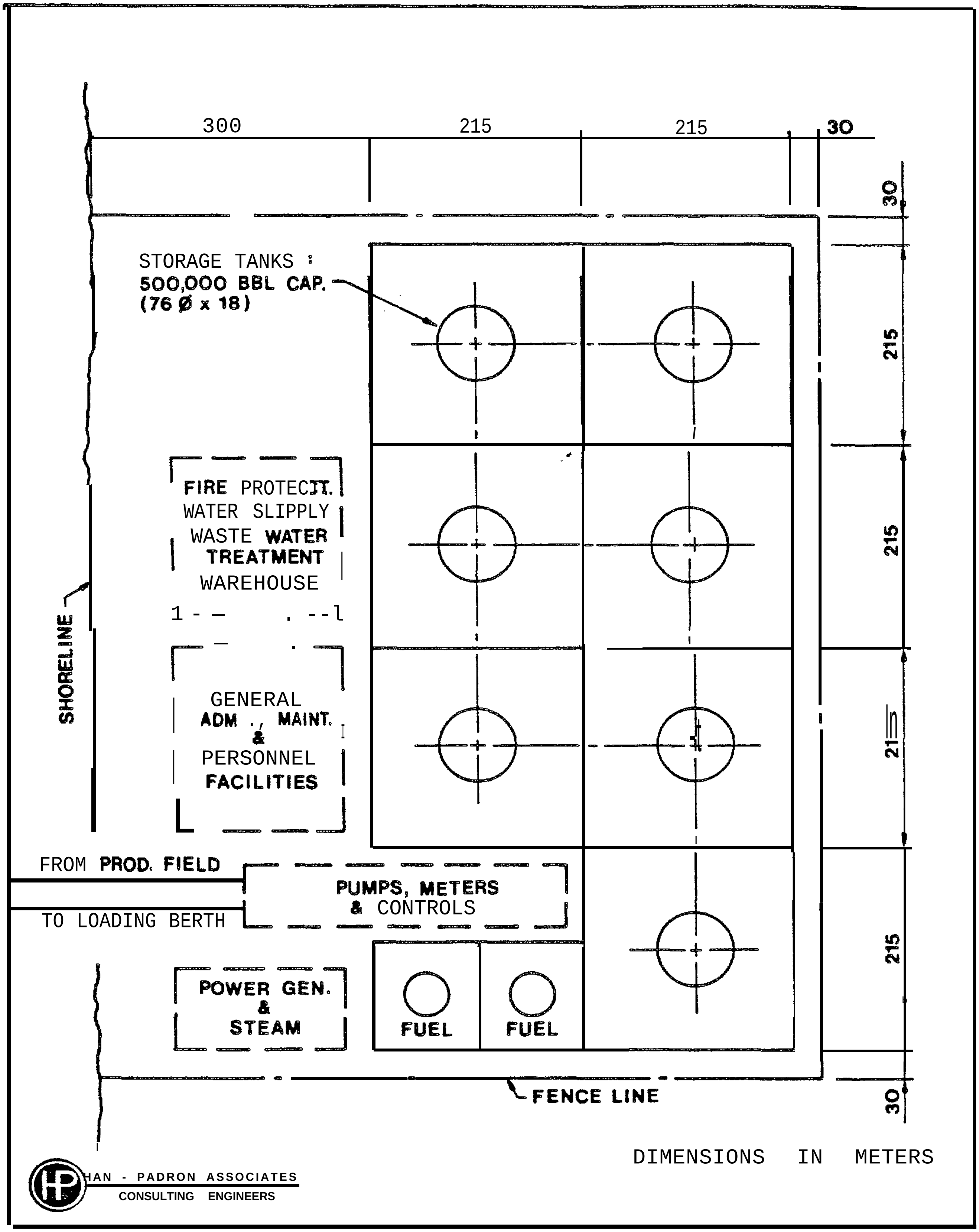

Figure 3-29. Onshore storage facilities typical layout.

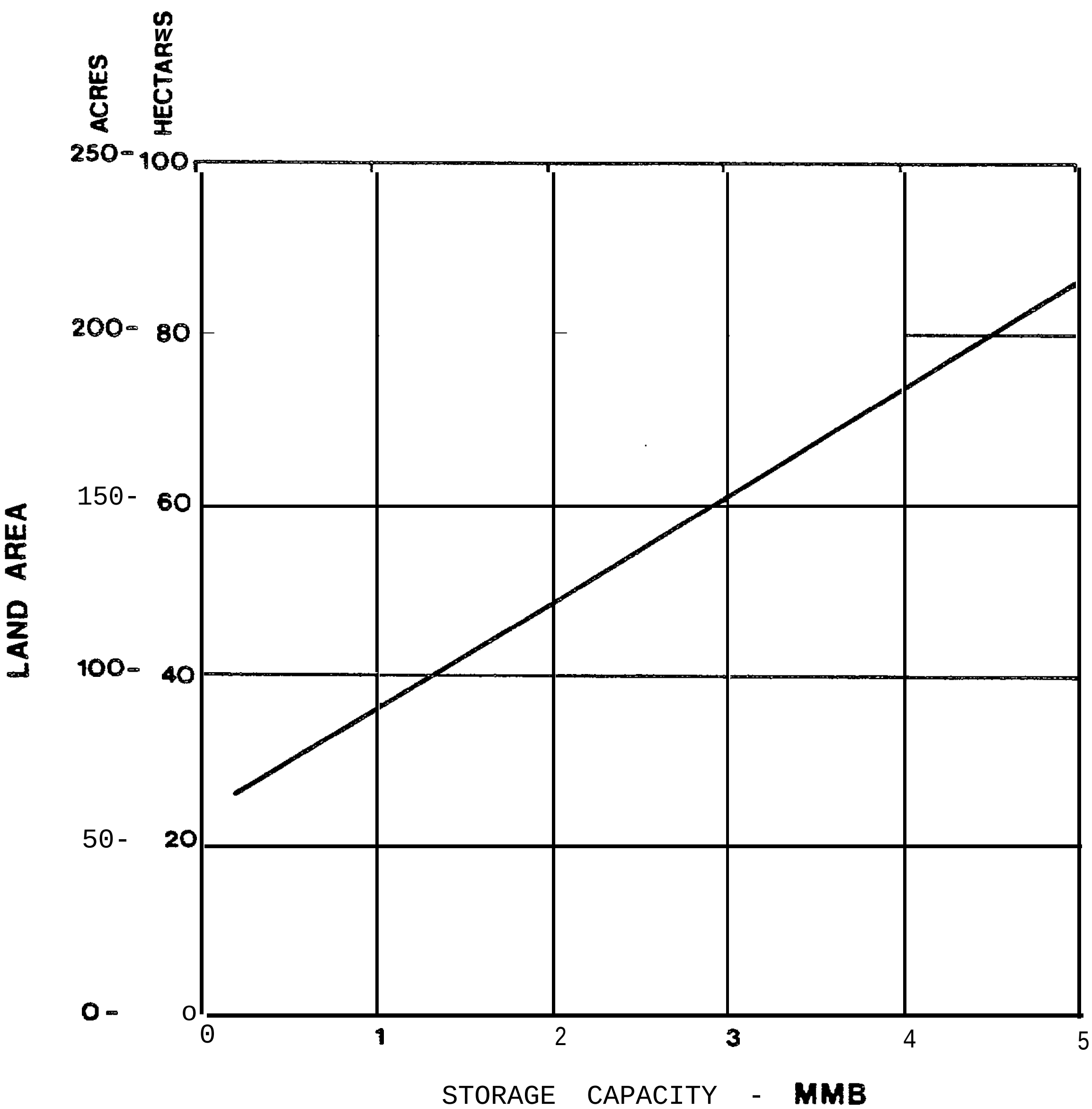

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Figure 3-30. Land area requirement versus crude oil storage capacity.

The capital cost of the storage facilities, also as a function of storage capacity, is shown in Figure 3-31. This cost does not include the cost of the pumping and metering system which have been included in the cost of the loading/unloading marine pipelines. The annual operating cost, based on an operating crew of 25 people, with a shift factor of two and a rotation factor of two, and maintenance cost at 2 percent of capital cost, is shown in Figure 3-31. The operating cost is not very sensitive to the volume of storage provided.

3.5.5 Tanker Loading/Unloading Pipelines

The pipelines connecting the crude oil storage facilities to the tanker loading 'or unloading berths are sized to load or unload tankers in 12 hours. This requires a maximum loading/unloading rate of 156,000 barrels per hour for a 250,000 DWT tanker, which is the maximum rate that can be accommodated by two 24 inch diameter hoses. With present technology it would probably not be practical to use more than two hoses nor larger than 24 inch diameter.

The length of the loading/unloading pipelines depends on a number of factors, the most important of which are the type of terminal (offshore, nearshore, transshipment), the location of the terminal and the size of the tankers using the terminal.

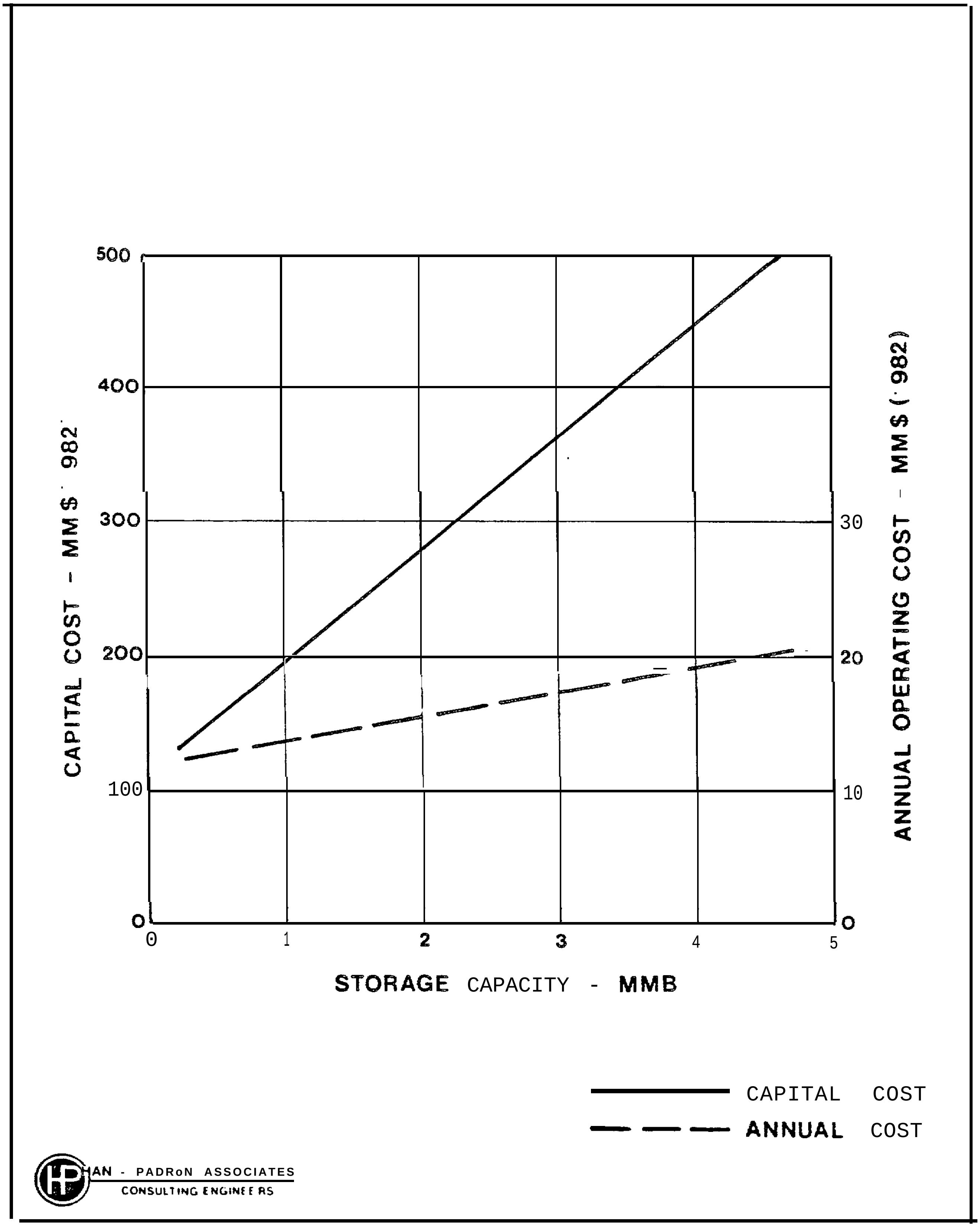

Figure 3-31. Onshore storage facilities capital and annual costs versus crude oil storage capacity.

a) Offshore Terminals

Some of the offshore terminal concepts considered provide for the tankers to moor directly to the storage facilities and thus, no loading pipeline as such is required. However, these alternatives do require a pipeline from the production platform to the offshore storage facilities. These pipelines are much smaller in diameter than loading lines because they transport the crude at the production rate rather than the tanker loading rate. It has been assumed that the offshore storage facilities will be located approximately 1.6 km (1 mi) from the production platform. Based on this assumption and the base case crude oil properties listeal in Section 3.3.1, the pipeline diameter and pumping horsepower have been calculated and are shown in Figure 3-32 as a function of production rate. Installed horsepower includes 50 percent spare capacity. Figure 3-32 is approximate because the pipe diameter and installed pumping horsepower are interdependent but it will provide reasonable data for preliminary estimates. The capital cost of this pipeline, including the cost of pumping facilities, is shown in Figure 3-33 as a function of production rate. The installed cost of pumping equipment, including the pumps, drivers, piping, valves and controls, has been assumed to be $2500 per installed horsepower. In addition, an allowance of $500 per installed horsepower has been added to cover the cost of the space on the drilling/production platform that the pumping equipment will occupy. Operating costs and manpower requirements are assumed to be included with the production platform.

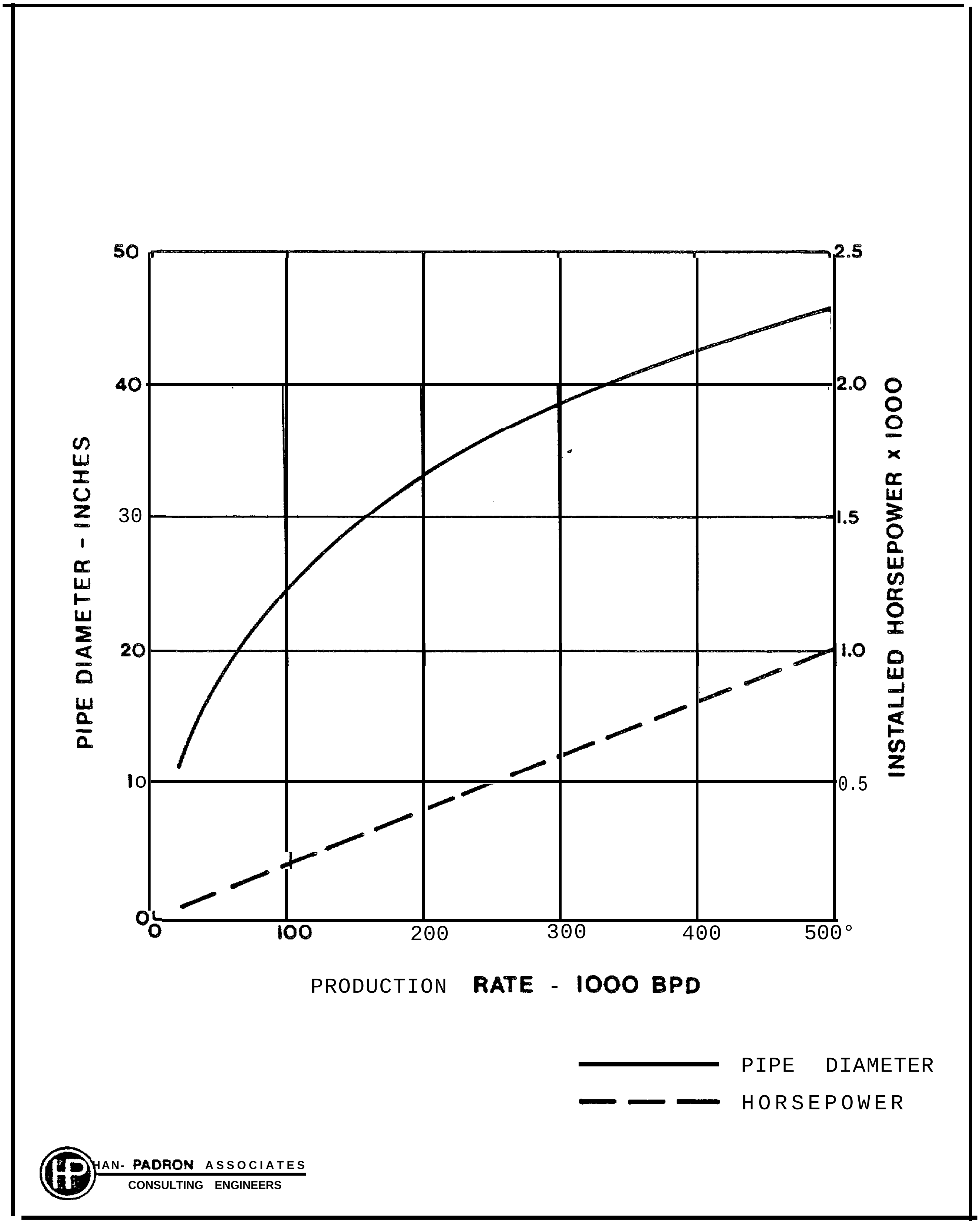

Figure 3-32. Offshore storage pipeline pipe diameter and installed horsepower versus production rate.

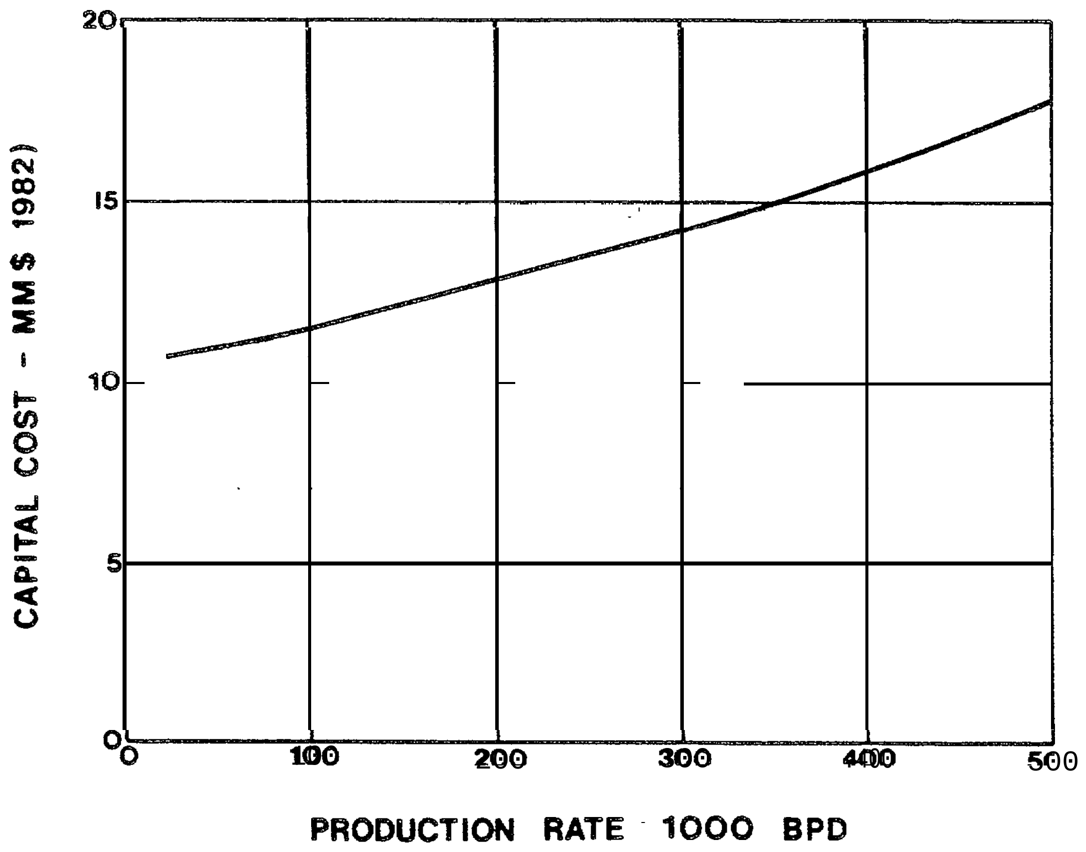

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Figure 3-33. Offshore storage pipeline capital cost versus production rate.

Other alternatives have the storage separate from the mooring system and located approximately 1.6 km (1 mi) distant. In this case the diameter, pumping horsepower, and the capital cost of the loading line can be expressed as a function of tanker size. Figure 3-34 shows the required pipe diameter and installed pumping horsepower. Installed pumping horsepower includes 50 percent spare capacity. This figure is valid only for crude oil with the base case properties listed in Section 3.3.1 and is, of course, approximate because the pipe diameter and installed pumping horsepower are interdependent for a given throughput. However, for preliminary evaluation purposes, the figure provides reasonable data. The capital cost of the pipelines, including the pumps, is shown in Figure 3-35. The cost of these pipelines, on a per mile basis, is much higher than for the marine pipelines discussed in Section 3.6 because they are relatively short and consequently mobilization and demobilization costs distributed over the length of the pipeline are quite high. The installed cost of pumping equipment, including the pumps, drivers, piping, valves, and controls, has been assumed to be $2,500 per installed horsepower.

Manpower requirements and annual operating costs are assumed to be included with the offshore storage facilities.

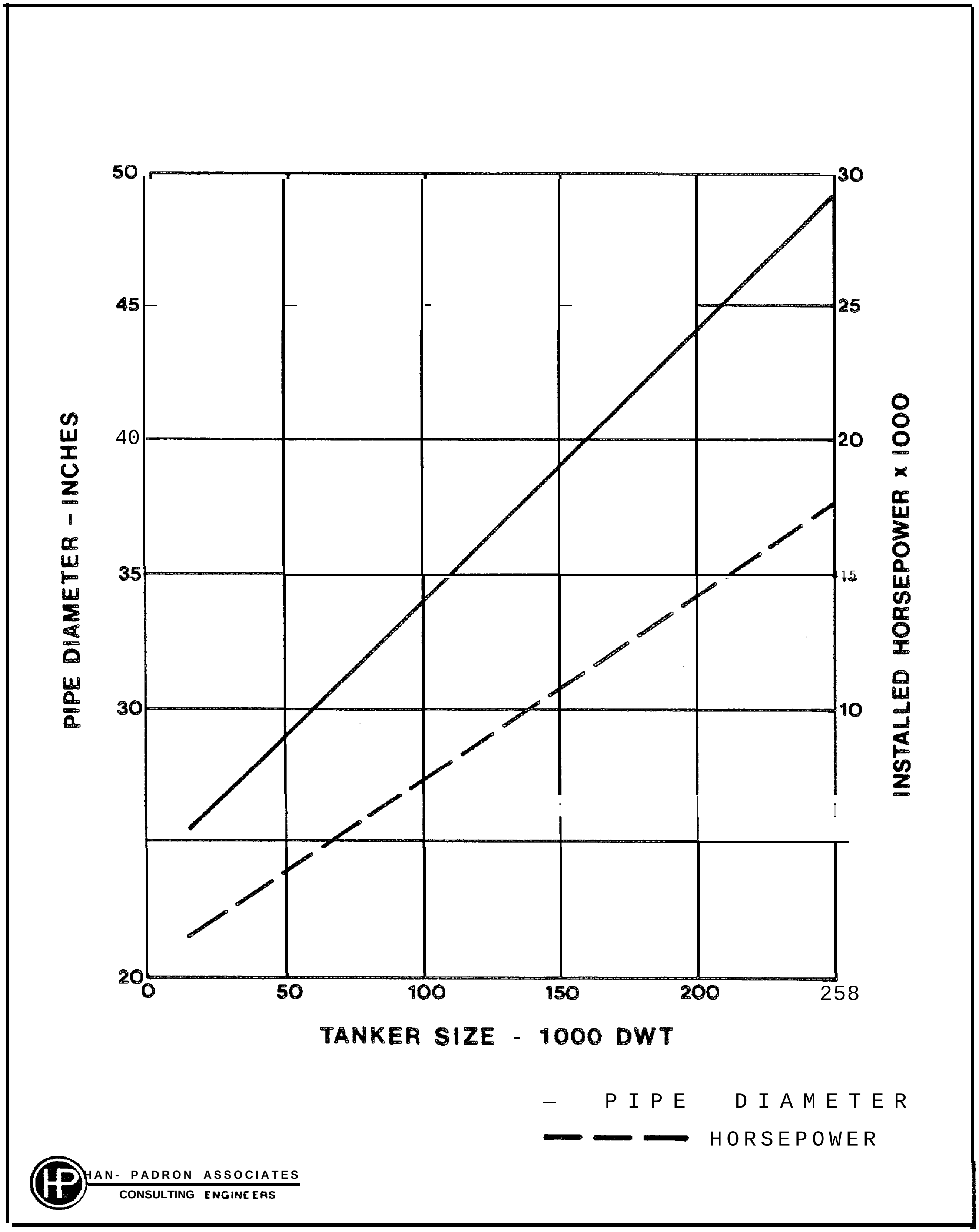

Figure 3-34. Offshore terminal loading pipeline pipe diameter and installed horsepower versus tanker size.

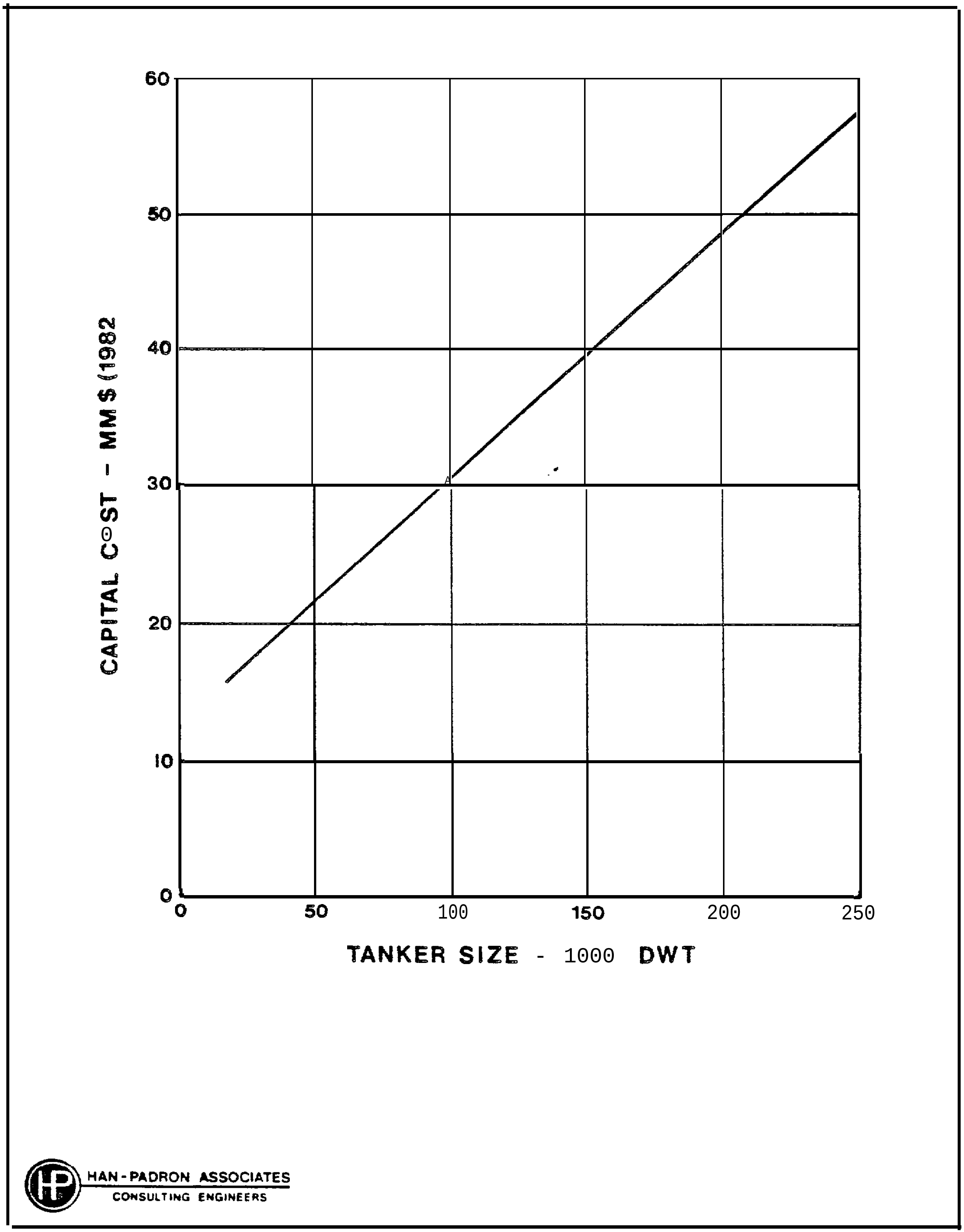

Figure 3-35. Offshore terminal loading pipeline capital cost versus tanker size.

b) Nearshore Terminal

The length of the loading line for a nearshore terminal depends on the seabed depth contours in the vicinity of the terminal and the maximum loaded draft of the tankers using the terminal. For all nearshore terminals considered, except the terminal in the Norton Basin, the difference in required pipeline length to accommodate the smallest to the largest tankers is negligibly small and a length of .2 km (1.25 mi) was used for all. For the Norton Basin, where the nearshore gradient of the seabed is very small, the pipeline length is quite sensitive to tanker size, as illustrated in Figure 3-36.

The diameter and pumping horsepower required for the nearshore terminals are shown as a function of tanker size, in Figure 3-37 for Scenario 1 where the length of the pipeline varies with tanker size and in Figure 3-38 for Scenarios 2 and 3 where the length of the pipeline does not vary with tanker size.

These pipelines are quite short compared to the marine pipelines discussed in Section 3.6 and the cost curves in that section are not valid for loading lines. The major portion of the cost of loading pipelines is the trenching, backfilling and erosion protection of the lines as well as the mobilization and demobilization of the pipeline installation equipment. The estimated capital cost of these lines is given in Figure 3-39 for Scenario 1 and Figure 3-40 for Scenarios 2 and 3, as a function of tanker size.

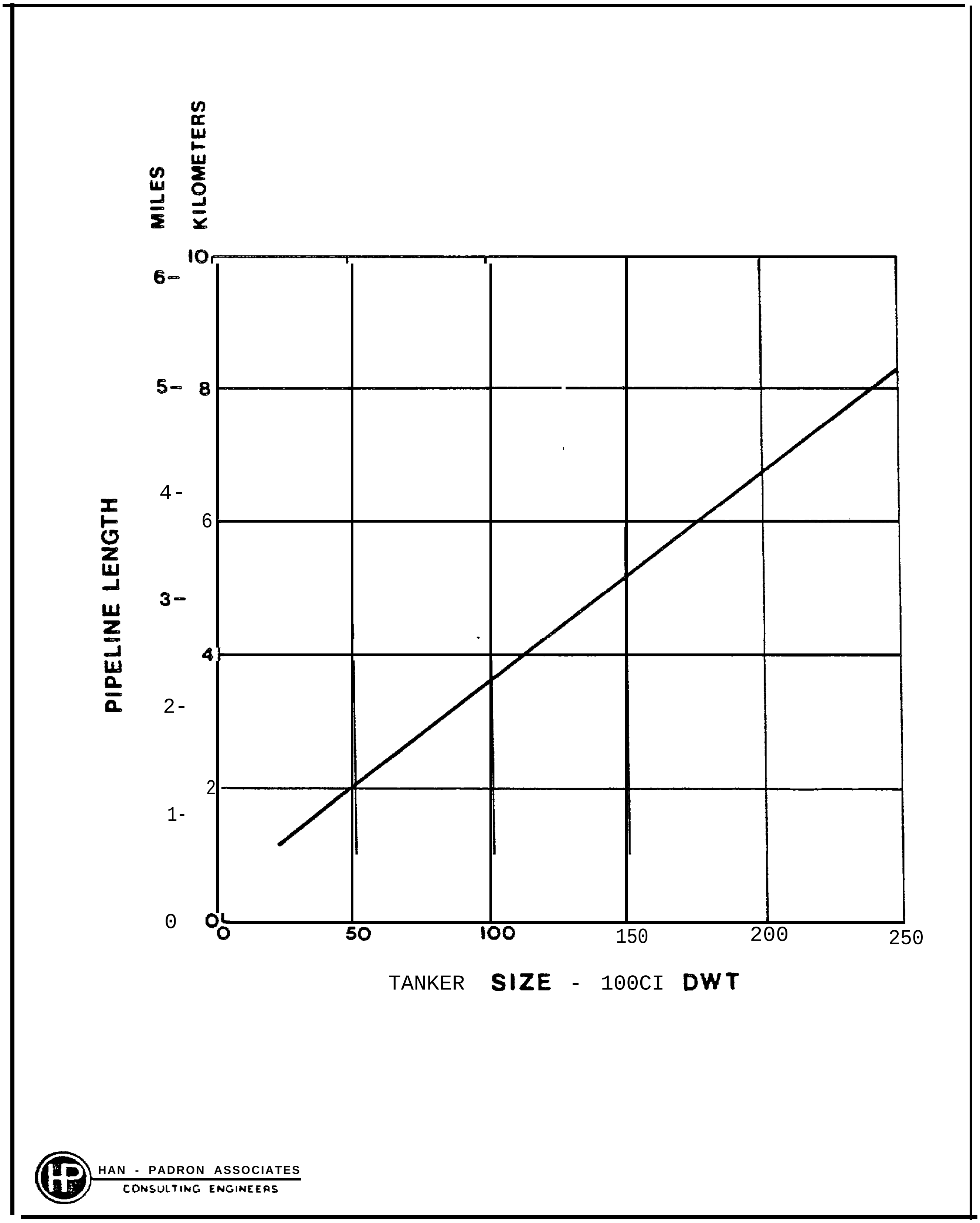

Figure 3-36. Scenario 1 nearshore terminal loading pipeline length versus tanker size.

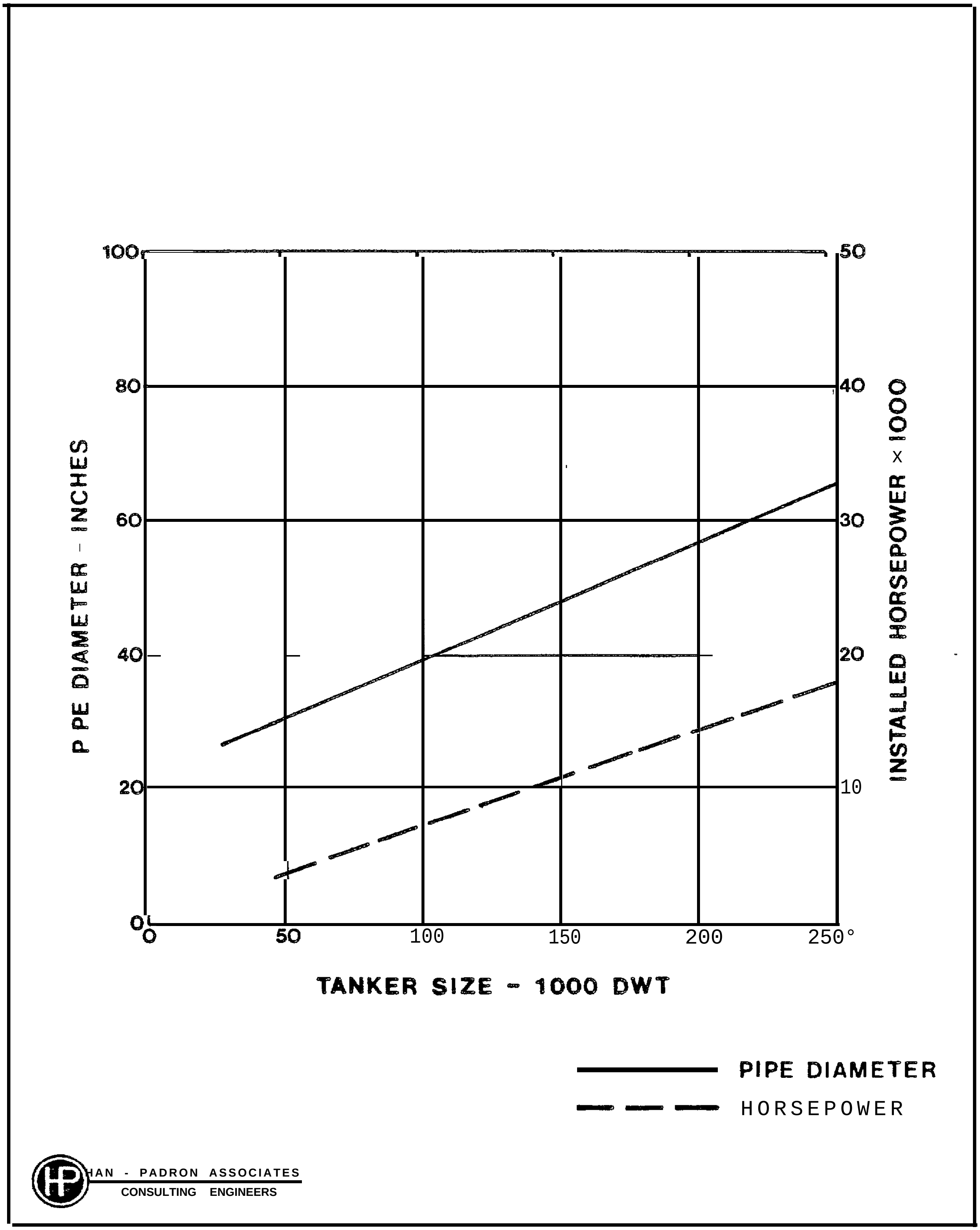

Figure 3-37. Scenario 1 nearshore terminal loading pipeline pipe diameter and installed horsepower **versus** tanker **size.**

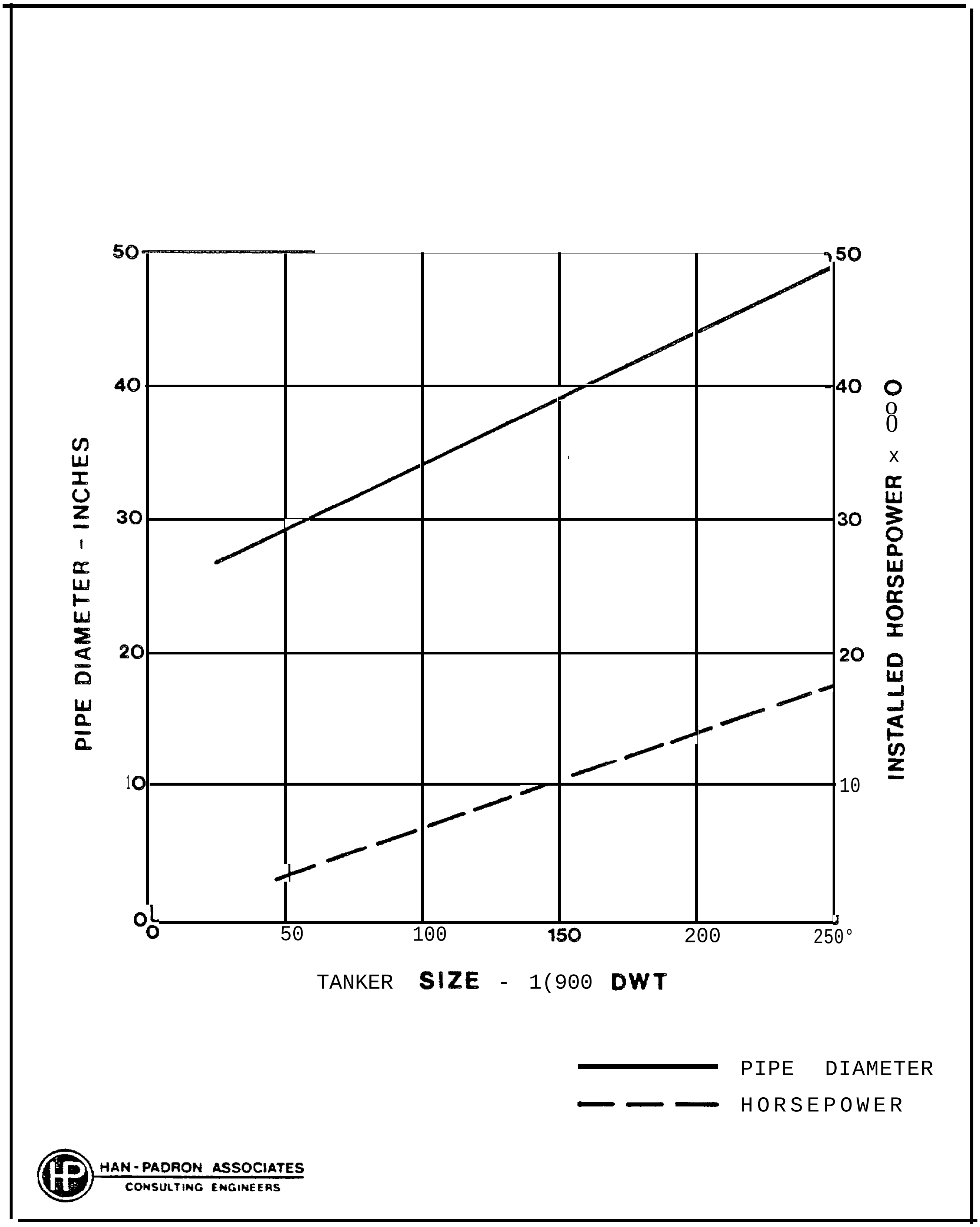

Figure 3-38. Scenarios 2 & 3 nearshore terminal loading pipeline pipe diameter and installed horsepower versus tanker size.

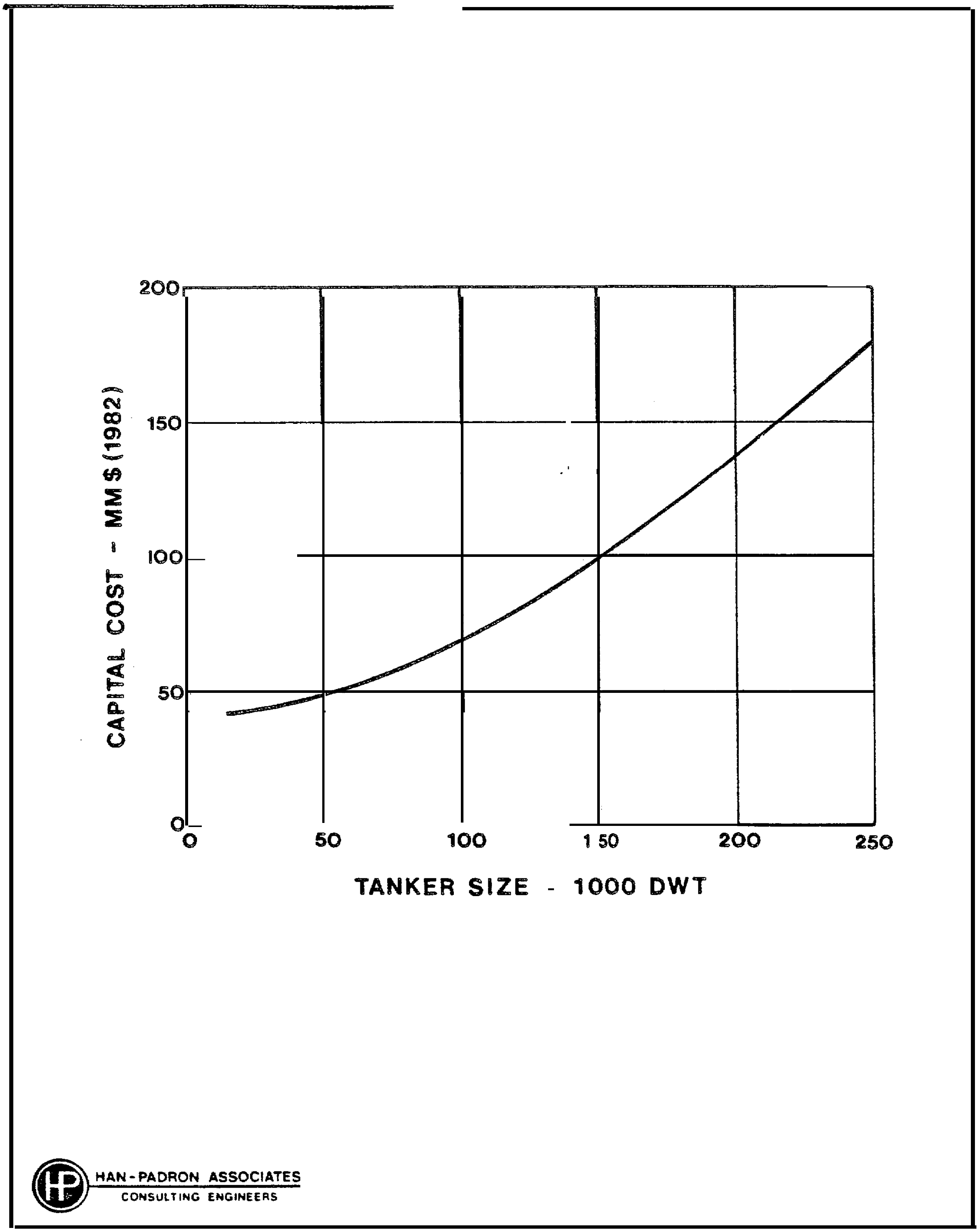

Figure 3-39. Scenario 1 nearshore terminal loading pipeline capital **cost versus** tanker **size.**

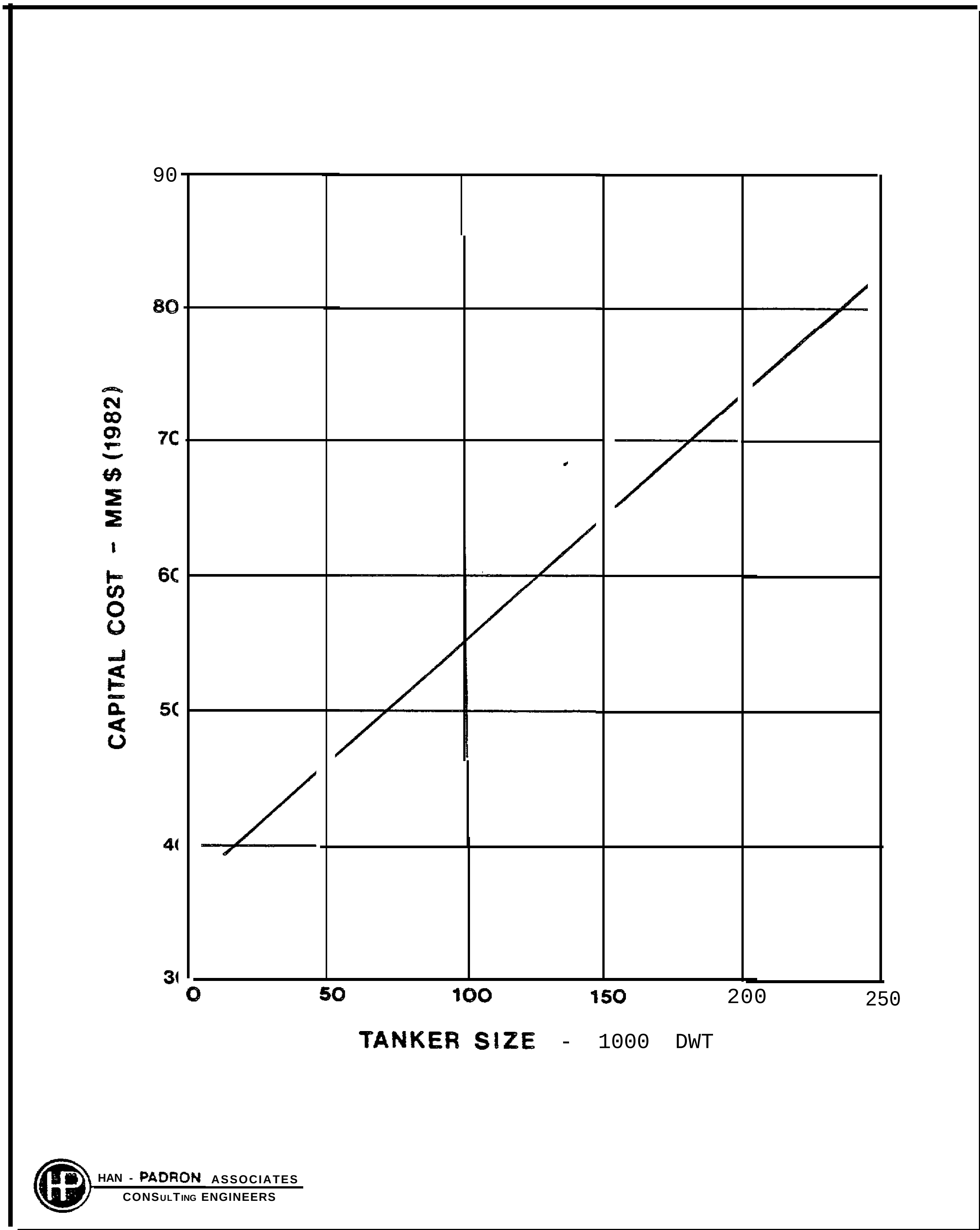

Figure 3-40. Scenarios 2 & 3 nearshore terminal loading pipeline capital cost versus tanker size.

The costs indicated in the figures include the cost of pumping and metering facilities which have been calculated on the basis of $2500 per installed horsepower.

Manpower requirements and annual operating costs are assumed to be included with the onshore storage facilities.

c) Transsshipment Terminal

The length of the pipeline connecting the transshipment terminal offshore loading/unloading system with the onshore storage system is essentially independent of the size of the tankers using the facility because deep water occurs quite close to shore in Balboa Bay. However, as for the other types of terminals, the diameter of the pipeline is a function of the size of the tankers since it has been assumed that all tankers will load/unload in 12 hours.

It has been assumed that the transshipment terminal loading/unloading lines are 2 km (1.25 mi) long and therefore the pipe diameter, horsepower and capital costs are the same as for the nearshore terminals of Scenarios 2 and 3 given in Figures 3-38 and 3-40.

Manpower requirements and annual operating costs are included with the storage facilities.

3.6 MARINE PIPELINE DESIGN PHILOSOPHY AND COSTS

Preliminary designs and cost estimates for all the marine pipelines required for each transportation alternative of each of the three selected scenarios have been prepared. The pipelines have been designed for the base case production rate and for each of the sensitivity case production rates using the base case crude oil properties.

Large diameter marine pipeline construction in the Bering Sea is technically feasible and would be similar to pipeline construction in the Northern North Sea. Marine pipeline design and installation considerations are described below.

3.6.1 Environmental Factors

Specific environmental design criteria for each of the three scenarios considered are contained in Chapters 4, 5 and 6. The environmental factors which most directly affect marine pipeline construction are discussed below.

The Norton Basin is only ice free 4 to 5 months per year. Therefore, the pipeline construction window will be relatively short compared with the more southern scenarios. The water depth is quite shallow, ranging from approximately 15 m (50 ft) to 40 m (130 ft) in the areas of interest, thus simplifying pipeline installation compared to the deeper water of the southern scenarios. Ice gouging and migration of the fine sand and silt seabed will require that the pipelines be installed in relatively deep trenches.

The Navarin Basin is ice free 6 to 8 months per year making the construction weather window approximately fifty percent longer than in the Norton Basin. The water depth is considerably deeper, generally between 75 and 150 m (250 and 500 ft), with a maximum depth of 2500 m (8200 ft). Silts generally characterize the shelf and slope of the Navarin Basin but there is a zone of coarser sediment at the shelf break, on the upper slope, and in the heads of submarine canyons. Ice gouging is, of course, not a consideration and the seismicity of the area is not severe.

The St. George and North Aleutian Basins are ice free approximately 9 months per year with the southern portions of the basins virtually ice free year round. Thus, with a minor amount of ice management, pipelaying operations could take place year round. The water depth in the majority of the two basins is less than 150 m (500 ft) but the southwest portion of the St. George Basin has water depths greater than 2500 m (8200 ft). One of the most active seismic zones in the world is within 500 km (300 mi) of the southern boundary of the St. George and North Aleutian Basins. Since ice gouging is not a problem, pipelines could be laid without burial to reduce the probability of an active fault shearing and breaking them. The surficial cover is generally silt to silty sand, with the finer grain sizes located in the center of the basin and the coarser sediment in the areas of shallower depth. Therefore, pipelines laid without burial would require periodic inspections to locate suspended spans caused by faulting. In the event that regulations require burial of pipelines in this area, methods for preventing excessive spills in the event of a pipeline break must be investigated.

3.6.2 Route Selection

In general, marine pipeline route selection for this study was based on using the minimum length of line to reach landfall, except for Scenario 3. For this scenario, the marine pipeline route was based on reaching a landfall that would require a relatively short land pipeline, over terrain that is not too rugged, to reach the Balboa Bay tanker loading terminal. All landfall locations indicated are for developing pipeline lengths and costs only. No attempt has been made to select the optimum locations for these landfalls. The selection of the optimum location depends on many factors, the evaluation of which are beyond the scope of this study.

3.6.3 Design

Preliminary designs for the marine pipelines for each alternative and each sensitivity production rate have been developed. For each case there are a number of combinations of pipe diameter, wall thickness, weight coating thickness and pump discharge pressure that would satisfy the conditions. An optimized pipeline design would require a detailed evaluation of the interrelationship of all these factors to minimize the life cycle cost of the system. For preliminary design purposes, reasonable combinations of these factors were selected based on past. experience with existing pipelines and it is anticipated that the major pipeline elements are reasonably close to those which would be obtained through a final design process.

Due to the deep water and ice cover, intermediate booster pump stations would not be cost effective on the marine pipelines, even the very long pipelines of Scenarios 2 arid 3, and all marine pipeline designs have been based on providing no booster stations. The pipeline pressure drop calculations are based upon Darcy's general flow equation with friction factors taken from Stanton's Diagram utilizing F.H. Moody's relative roughness data. The pipe wall thicknesses developed meet the requirements of ANSI B31.4, "Liquid Petroleum Transportation Piping Systems," for the internal pressure developed. In most cases API-5LX-42 pipe was selected. However, in a few cases, particularly the high throughput, long pipelines, API-5LX-52 pipe was required. For marine pipelines, it is frequently found that the pipelaying stresses during construction exceed operating stresses and it is necessary to increase the wall thickness for construction purposes. For this reason, wall thicknesses greater than required for internal pressure were provided on the smaller lines. A detailed evaluation of construction techniques may indicate that slightly greater wall thicknesses are required for some of the large diameter pipelines also.

Marine pipelines would be waterproofed and weight coated. A common method of waterproofing is to coat the pipe with coal tar and wrap with two applications of glass wrap and a felt outer wrap with hot coal tar applied between each wrap. Waterproofing of the pipe is extremely important to the longevity of the pipeline and a thorough investigation of optimum methods of waterproofing for this rugged service would be required in final design. All pipelines are assumed to be catholically protected.

The concrete weight coat would be reinforced with wire mesh. Concrete of densities ranging from 2.15 to 3.2 tons per cubic meter (135 to 200 pounds per cubic foot) are available. The weight coated pipe selected for the preliminary pipeline design has a minimum negative buoyancy of 1.25 with the pipeline empty.

The concrete weight coat required is as follows:

PIPE DIAMETER in.	WEIGHT COAT THICKNESS cm (in.)
<14	4.0 (1.5)
14-24	5*0 (2.0)
26-30	6.5 (2.5)
32-34	7.5 (3.0)
36-40	9.0 (3.5)

The viscosity characteristics of the base case crude oil, as defined in Section 3.3.1, are 40 SSU at 38°C (100°F) and 52 SSU at 25°C (77°F), with a pour point of -15°C (5°F). By use of the "A.S.T.M. Standard Viscosity-Temperature Charts for Liquid Petroleum Products, (D-341)" the viscosity at 0°C (32°F) was determined to be 260 SSU .

It would not be practical or cost effective to insulate the long pipelines and the concrete weight coat is not a good insulator. For the preliminary designs, it was assumed that the crude oil would enter the pipeline at 57°C (130°F). For an 18 Inch diameter marine pipeline, operating at 125,000 BPD in a seawater environment at 0°C (32°F) , the temperature of the crude falls to 5°C (41°F) after 16 km (10 mi) and to 0°C (32°F) after 64 km (40 mi). For preliminary design purposes, in cases where the pipelines are shorter than 64 km (40 mi), the average temperature of the crude oil in the lines was taken into account. However, for longer pipelines, the viscosity at 0°C (32°F) was used for the whole line. This is slightly conservative and will result in installing pumps and drivers capable of starting up a cold pipeline at design flow rates immediately.

For the St. George Basin cases, with 60 km (38 mi) of land pipeline, it is assumed that the line will be buried deep enough to protect it from ambient temperature so that the crude temperature will not fall below 0°C (32°F).

The pumping equipment selection philosophy for each case is to install two 50 percent capacity pumps, with gas combustion turbine drivers, plus a third 50 percent capacity pump and driver as a spare. Flash gas from the gas-oil separators would be used to fuel the gas combustion turbines.

Figures 3-41 and 3-42 present the results of the preliminary design of the marine pipelines. Figure 3-41 illustrates the required pipe diameter as a function of pipeline length for the five crude oil peak production rates considered. Figure 3-42 illustrates the required installed horsepower (including the 50 percent capacity spare) as a function of pipeline length for the same five production rates. These figures are valid only for crude oil with the properties listed above and are approximate because the pipe diameter and installed pumping horsepower are interdependent for a given pipeline length and production rate. For example, by providing a larger pipeline than indicated in Figure 3-41, for a given pipeline length and production rate, the installed horsepower required would be less than that indicated in Figure 3-42. However, for preliminary evaluation of a particular scenario, Figures 3-41 and 3-42 will provide reasonable estimates of pipe diameter and installed horsepower.

3.6.4 Installation Methods

There are no existing marine pipelines in the Bering Sea,

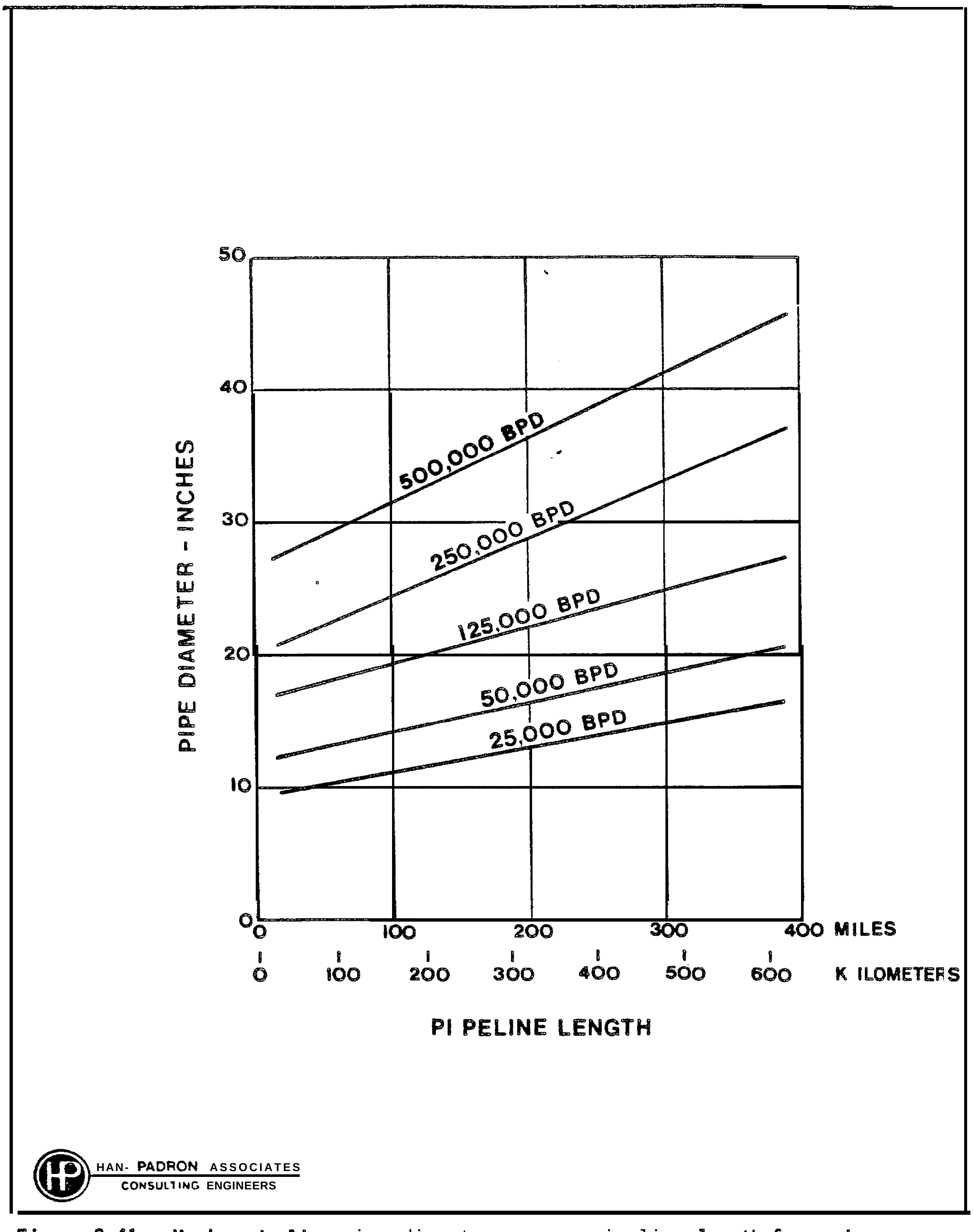

Figure 3-41. Marine pipeline pipe diameter versus pipeline length for various production rates.

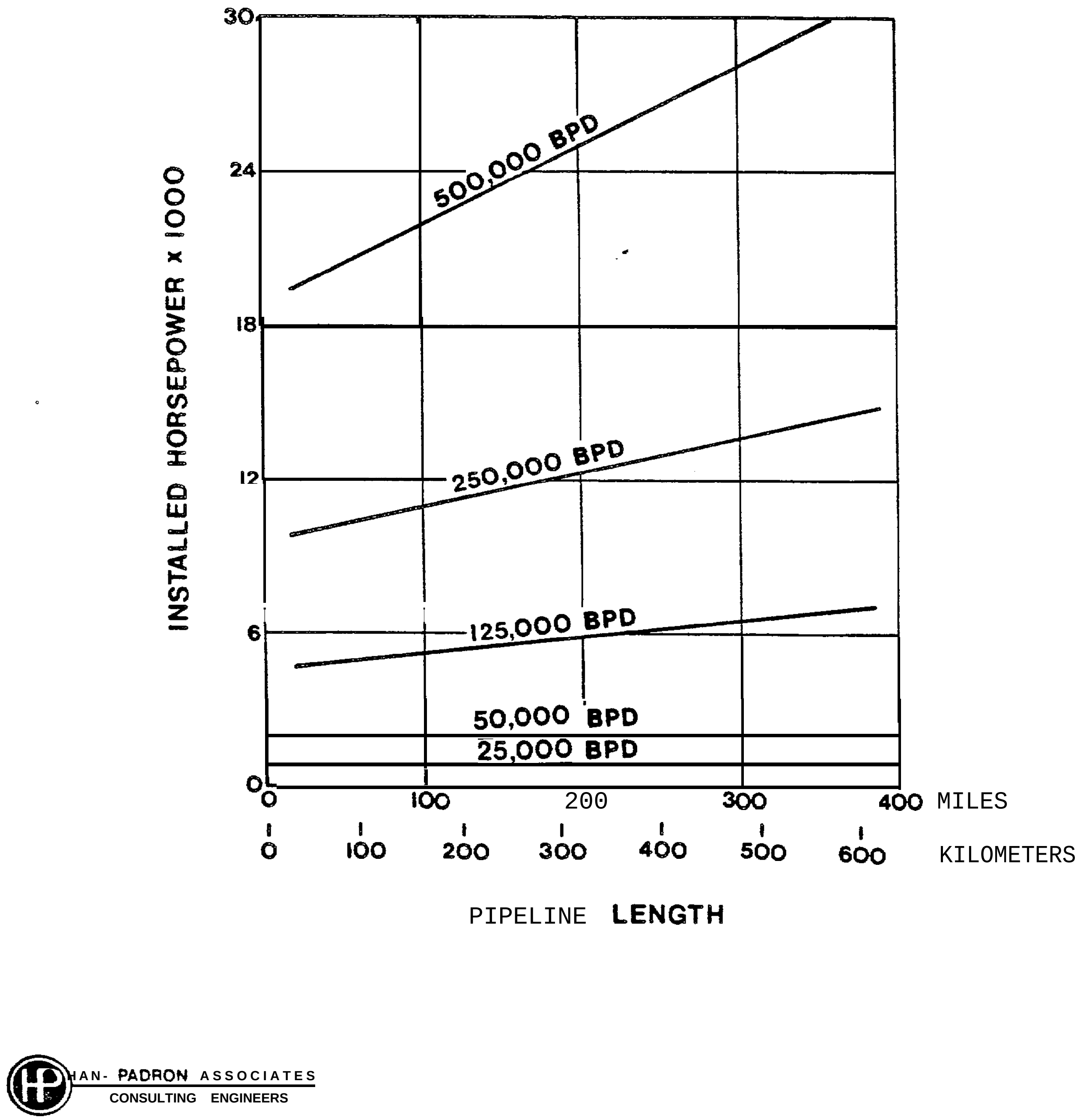

Figure 3-42. Marine pipeline installed horsepower versus pipeline length for various production rates.

however, there is no doubt that their construction is technically feasible. It is anticipated that the long pipelines would be installed by a large semi-submersible lay barge. These vessels can lay pipe at a rate of 1,800 to 2,100 m (6,000 to 7,000 ft) per day and can operate in significant wave heights of 4.5 to 5.5 m (15 to 18 ft). For the relatively short pipelines required in the Norton Basin, the bottom tow method may be used instead of the lay barge method, but for cost evaluation purposes it has been assumed that either method would result in the same cost.

Regulations regarding burial of pipelines in the Bering Sea have not been established. Pipelines in the Norton Basin will require burial due to ice gouging. Since regulations in the North Sea require all pipelines to be buried, it has been assumed, for cost estimating purposes, that all Bering Sea pipelines will be buried. A large trenching barge for pipeline burial can operate in seas up to approximately 1.5 m (5 ft) significant wave height and can travel at a rate of 1 to 3 m (3 to 10 ft) per minute.

3.6.5 costs

There are no cost data on Bering Sea marine pipelines available on which to base construction cost estimates. An evaluation of North Sea pipeline costs is contained in Appendix A of this report. For construction cost estimating purposes, it has been assumed that marine pipeline construction costs in the Bering Sea will be 25 percent higher than costs in the North Sea due to the much greater distances from supply bases and the reduced construction season. Figure 3-43 shows pipeline construction costs versus pipeline diameter developed on this basis. The installed cost of pumping equipment, including the pumps, drivers, piping, valves and controls, has been assumed to be $2,500 per installed horsepower. In addition, an allowance of $500 per installed horsepower has been added to cover the cost of the space that the pumping equipment will occupy on the drilling/production platform. The actual cost of such space cannot be determined within the scope of this study and the selection of $500 per horsepower is consequently quite arbitrary.

Operating costs of marine pipelines are very difficult to establish. Typically, operating costs are considered to range between 1 and 5 percent of capital costs. For purposes of this study, it has been assumed that average annual operating costs will be approximately 3.5 percent of the capital cost, as indicated in Figure 3-43.

Marine pipeline manpower requirements are included with the drilling/production manpower.

3.6.6 Sensitivity

The feasibility and cost of long marine pipelines can be extremely sensitive to the properties of the crude oil they must

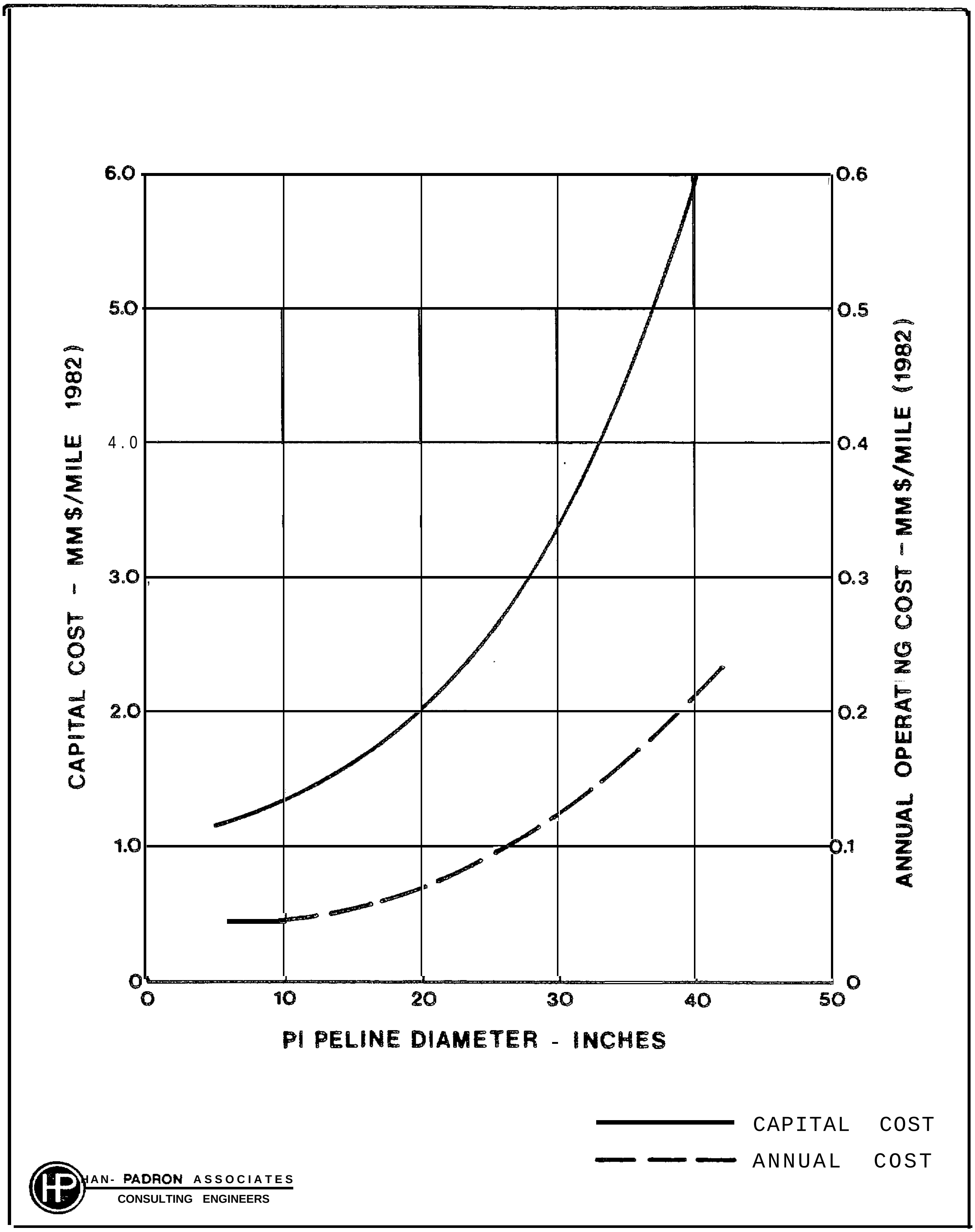

Figure 3-43. Marine pipeline capital and annual costs versus pipeline diameter.

transport. All of the preliminary designs have been based on the base case crude oil properties listed in Section 3.3.1. For the sensitivity case properties listed, i.e., a pour point of 16°C (61°F) and a Saybolt Universal viscosity of 300 seconds at 25°C (77°F) and 200 seconds at 38°c (100°F), a long marine pipeline would not be feasible. As mentioned above, in an 18 inch diameter pipeline, operating at 125,000 BPD in a seawater environment of 0°C (32°F), the temperature of the crude oil drops to 5°C (41°F), well below the pour point, in just 16 km (10 mi). Therefore, no further pipeline analyses of this case were considered. . .

3.7 LAND PIPELINE DESIGN PHILOSOPHY AND COSTS

Other than the short land pipelines required at each tanker nearshore or transshipment terminal, only two of the sixteen base case transportation alternatives considered include a land pipeline. Alternative 1A includes a land pipeline from the Nome area to a nearshore tanker loading terminal in Cook Inlet and Alternative 3A includes a land pipeline across the Alaska Peninsula to a nearshore tanker loading terminal in Balboa Bay.

The pipeline to Balboa Bay is approximately 60 km (38 mi) long. This pipeline has been sized as part of the much longer marine pipeline from the St. George Basin to the Alaska Peninsula and is based on the assumption that a booster station would not reduce total pipeline capital or operating costs. It is also assumed that the pipeline will be buried sufficiently to prevent the crude oil temperature from dropping below 0°C (32°F).

The land pipeline from Nome to Cook Inlet is some 1125 km (700 mi) long and will be extremely expensive. No preliminary design work was carried out for this pipeline. The National Petroleum Council (1981) report has an extensive treatment of land pipelines, including this alternative, and land pipeline sizes and costs, including booster stations, were developed from that report. These pipe diameters versus production rate are shown in Figure 3-44. Land pipeline capital costs are shown in Figure 3-45 versus pipeline diameter and versus production rate in Figure 3-46. It has been assumed that average annual operating costs for land pipelines will be 3.5 percent of capital costs and this is also indicated in Figures 3-45 and 3-46. Since t-he alternative utilizing this pipeline is far more costly than the optimum alternative, manpower requirements have not been estimated.

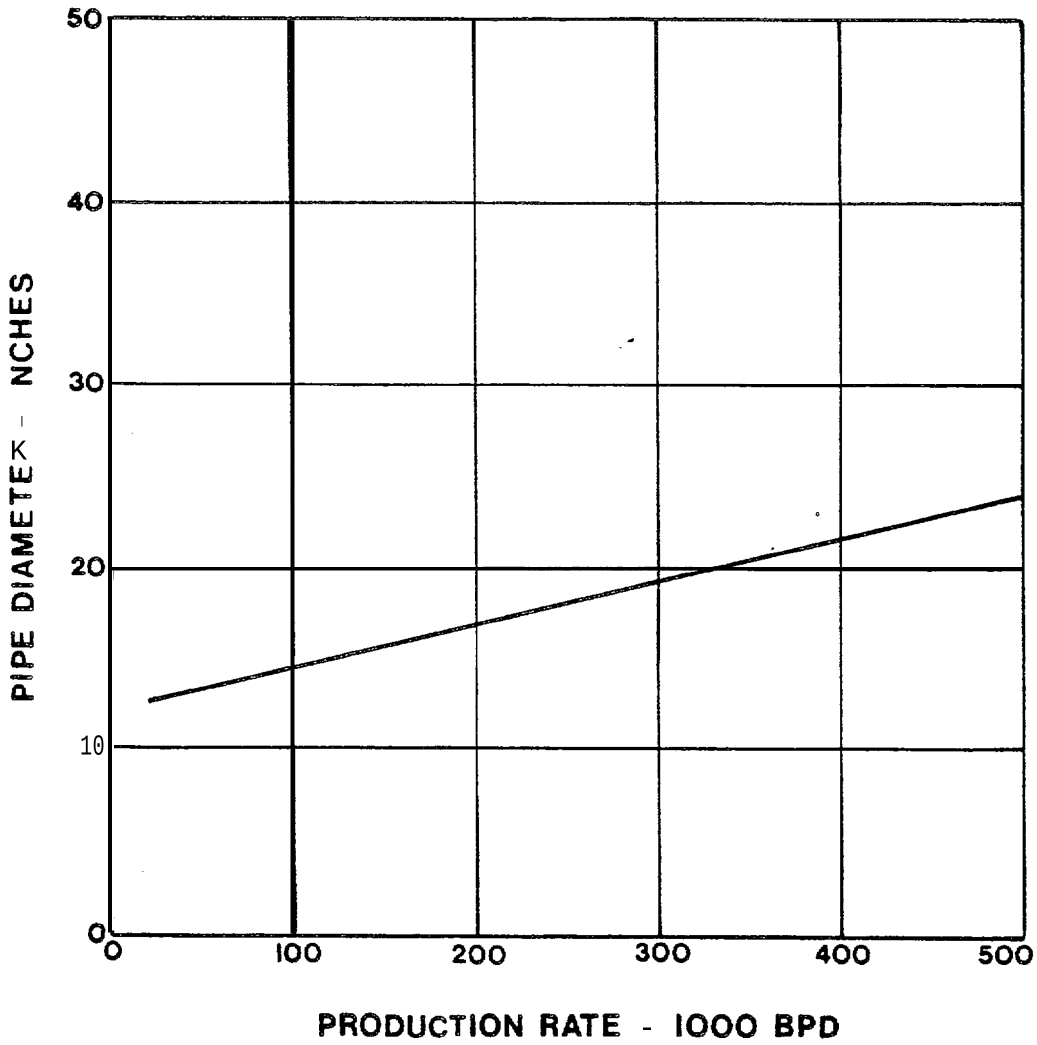

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Figure 3-44. Nome to Cook Inlet land pipeline pipe diameter versus production rate.

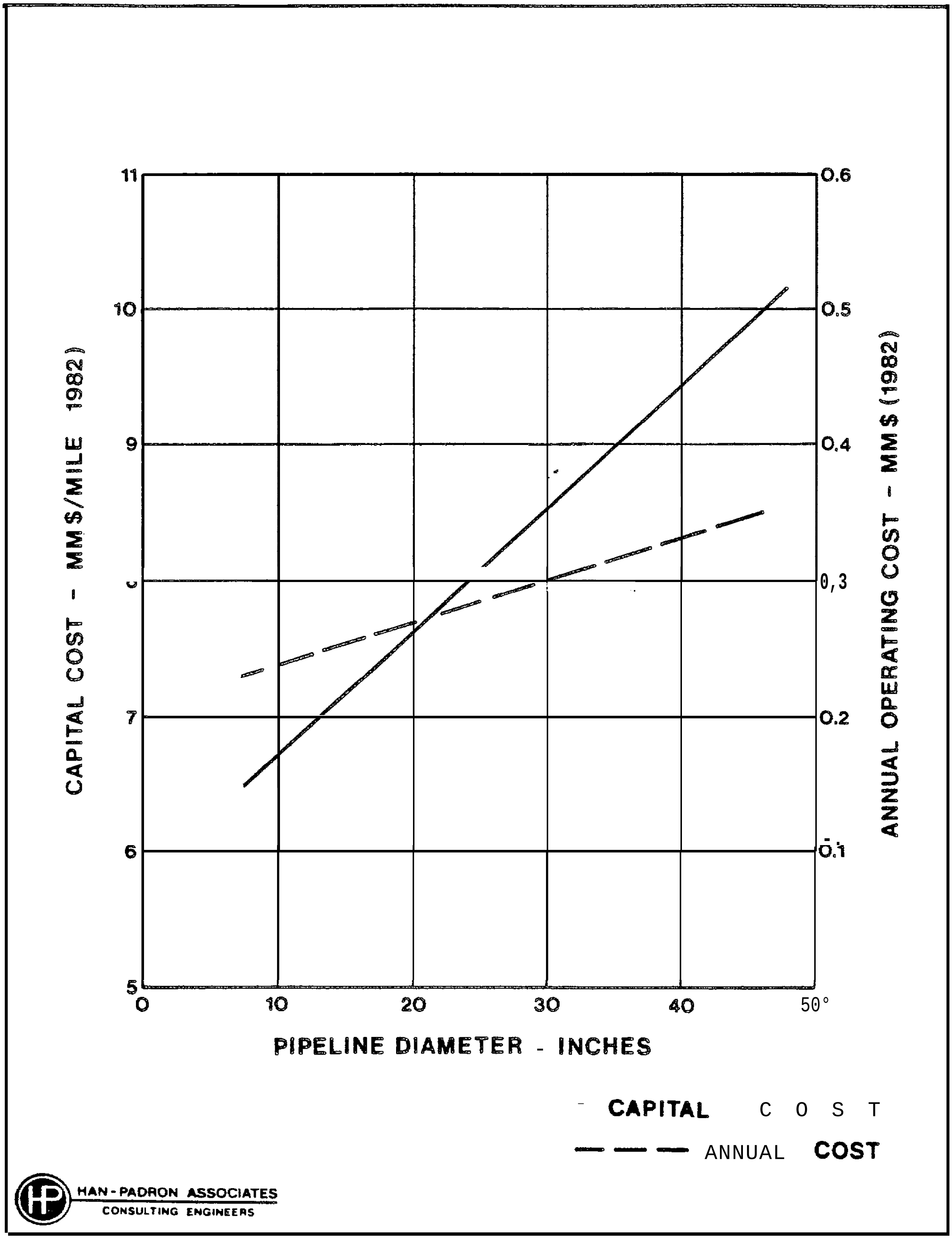

Figure 3-45. Land pipeline capital and annual costs versus pipeline diameter.

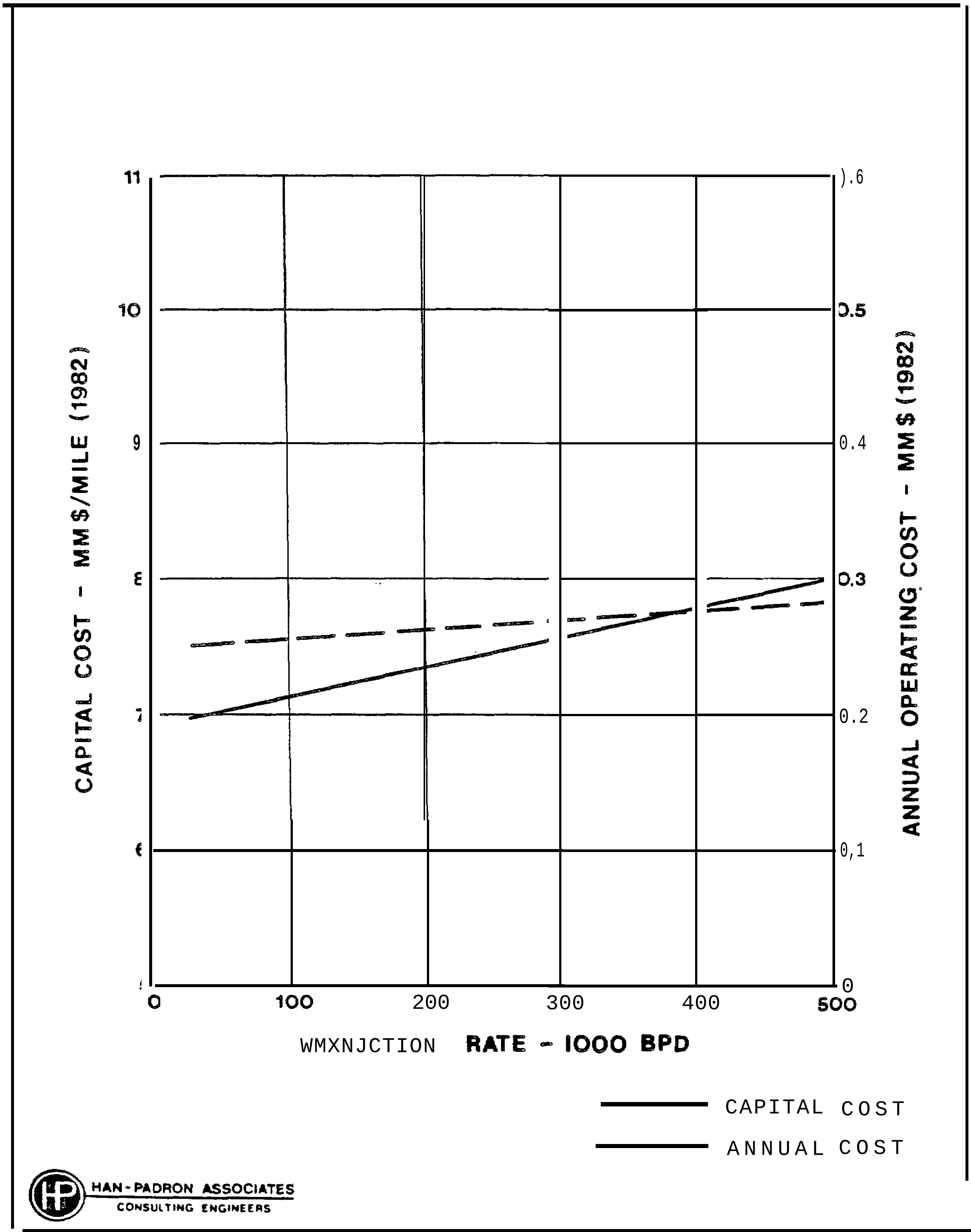

Figure 3-46. Land pipeline capital and annual costs versus production rate.

4.0 SCENARIO 1 - NORTHERN BERING SEA

This chapter presents the technological and cost analysis of crude oil transportation systems for the Northern Bering Sea, the Norton Basin Lease Sale area. The site selected as representative of this area is indicated in Figure 4-1. The location is based on what appears to be the center of the high interest tracts of the lease sale area and is representative of the environmental conditions in the area. All the pertinent characteristics of this scenario are defined and used in the evaluation of the transportation alternatives in the following sections. A number of the scenario parameters are varied to carry out sensitivity analyses.

4.1 ENVIRONMENTAL DESIGN CRITERIA

The background and basis for the selection of the environmental design criteria used for this study are described in Section 3.1. The specific design criteria for the Northern Bering Sea scenario are listed below.

4.1.1 Ice Conditions

The properties of sea ice listed below are based on a salinity of 7 ppt, an approximate weekly minimum average air temperature of -25°C with a resultant average ice temperature of -6°C.

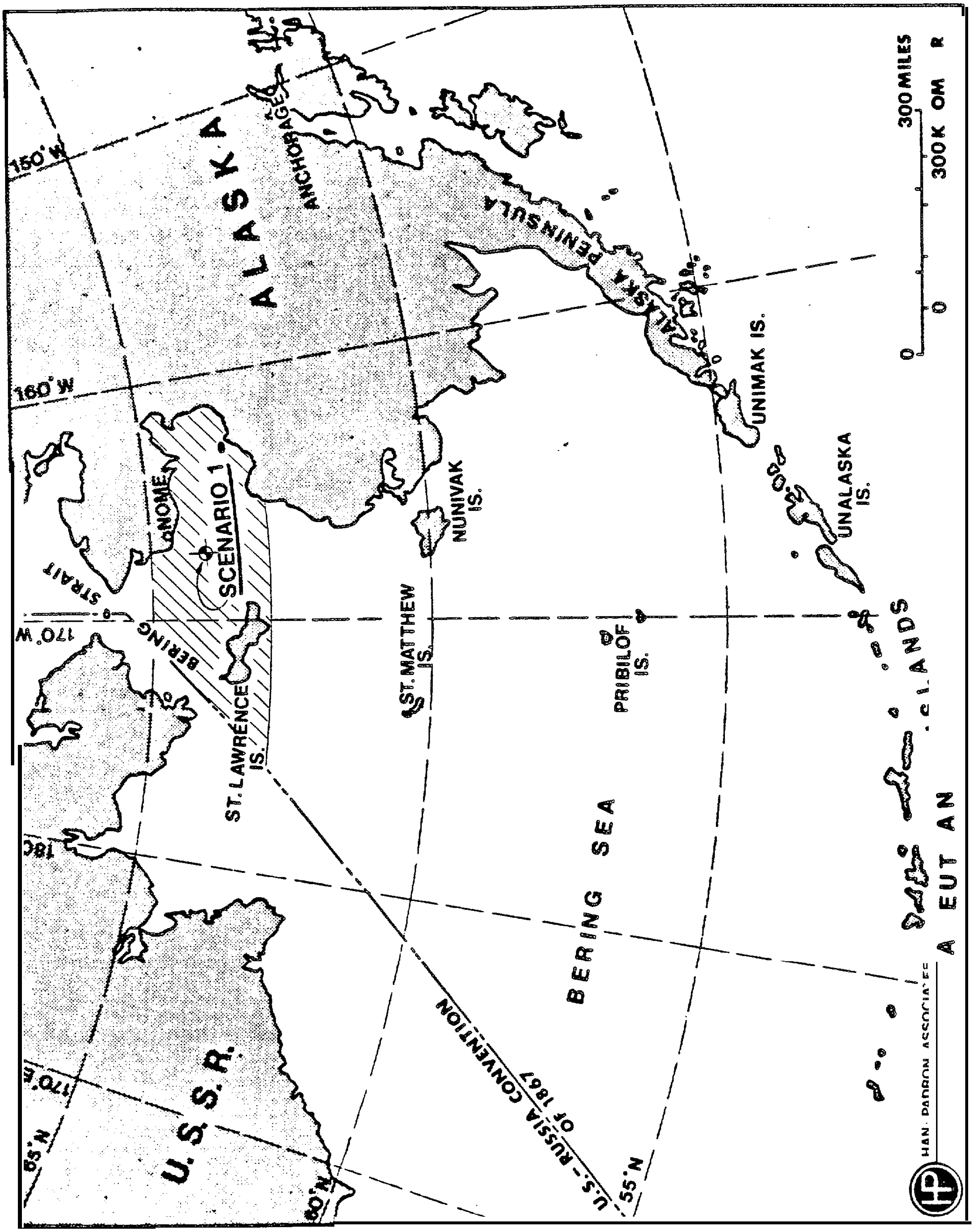

Figure 4-1. Location of Scenario 1.

a) Ice Strengths

Compressive	=	3900 kPa (560 psi)
Flexural	=	48U kPa (70 psi)
Shear	=	700 kPa (100 psi)

b) Ice Modulus of Elasticity and Other Properties

Modulus of elasticity	=	1,900 mPa (280,000 psi)
Poisson's ratio	=	0.33
Density	=	935 kg/cu m (58 pcf)
Coefficient of friction		
ice/steel	=	0.15
fee/concrete	=	0.30

c) Level Ice Characteristics

Average thickness	=	1.0 m (3.3 ft)
Max. rafted thickness	=	2.0 m (6.6 ft)

d) Ice Ridges

	100 Year	1 Year
Sail height, m (ft)	5.2 (17.0)	3.4 (11.0)
Keel depth, m (ft)	18.3 (60.0)	13.4 (44.0)
Depth of consolidation, m (ft)	10.4 (34.0)	7.0 (23.0)

e) Ice Coverage and Concentration

Period of greater than 0% probability of ice coverage — November 1 to July 1

	Concentration (oktas)								
	0	1	2	3	4	5	6	7	8
Frequency of Occurrence (days per year)	138	0	0	15	16	30	46	62	58

f) Ice Floe Velocity

Max. ice floe velocity = 0.75 mps (1.5 knots)

g) Superstructure Icing Rate

Max. icing rate = 1.9 cm (0.75 in.) per 3 hr

4.1.2 Waves

Max. wave height = 12 m (40 ft)

Corresponding wave period = 10 sec

Wave crest elevation above still water level = 7.6 m (25 ft)

4.1.3 Water Depth

Base case = 30 m (100 ft)

Min. case = 18 m (60 ft)

Max. case = 37 m (120 ft)

4.1.4 Winds

Mean summer wind	= 3.5 to 5 mps (7 to 10 knots) from south through southwest
Mean winter wind	= 5 to 7.5 mps (10 to 15 knots) from north through east
Max. one-minute wind	= 53 mps (103 knots)
Max. three-second gust	= 63 mps (123 knots)
Max. one-hour wind	= 42 mps (83 knots)

4.1.5 Currents

Max. surface current	= 1.5 mps (3 knots)
Max. bottom current	= 1.0 mps (2 knots)

4.1.6 Tides/Storm Surge

Tidal range	= 0.6 m (2 ft)
Storm surge	= 2.0 m (6.5 ft)

4.1.7 Geotechnical Conditions

	Base Case	Sensitivity Analysis
Soil type	fine sand	silt
Friction angle, Ø	35°	25°
Shear strength, kPa (psf)	0	0
Submerged unit weight, kg/cu m (pcf)	1040 (65)	960 (60)

4.1.8 Seismic Conditions

API Seismic Zone	1
API Acceleration Factor	0.05

4.1.9 Meteorological Conditions

Average annual max. temperature = -0.2°C (31.6°F)

Average annual min. temperature = -7.0°C (19.4°F)

Average annual precipitation = 41.4 cm (16.3 in.)

AVERAGE ANNUAL PERCENT FREQUENCY OF OCCURRENCE OF PRECIPITATION TYPES

Rain or Drizzle	10.2
Freezing Rain or Drizzle	0.7
Snow or Sleet	14.5
Total Precipitation	25.4

AVERAGE ANNUAL PERCENT FREQUENCY OF OCCURRENCE OF REDUCED VISIBILITY

Fog	15.2
Smoke or Haze	0.1
Blowing Snow	4.3
Total Reduced Visibility	19.6

4.2 DESCRIPTION OF TRANSPORTATION ALTERNATIVES

Several reasonable alternatives exist for transporting crude oil from the Northern Bering Sea. Alternatives which have been discussed in previous studies, even if not considered practical, are included to provide a uniform basis for comparisons. The alternatives considered include:

Alternative 1A

Marine pipeline and land pipeline to a nearshore terminal in Cook Inlet and conventional tanker to the U.S. West Coast (see Figure 4-2).

Alternative 1B

Marine pipeline to a nearshore terminal, ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 4-3).

Alternative 1C

Marine pipeline to a nearshore terminal and ice-strengthened tanker to the U.S. West Coast (see Figure 4-4).

Alternative 1D

Offshore loading of ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 4-5).

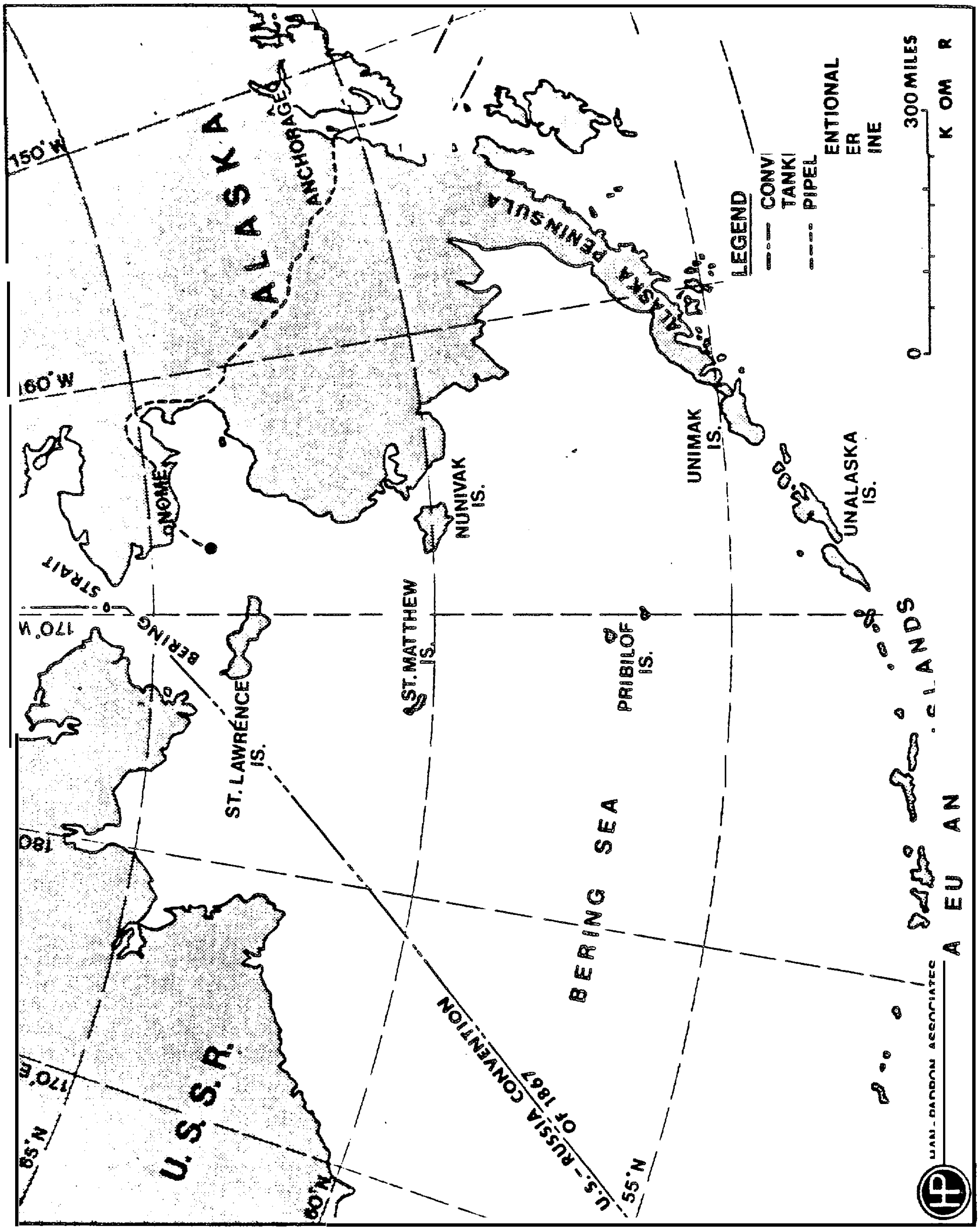

Figure 4-2. Scenario 1, Transportation Alternative A.

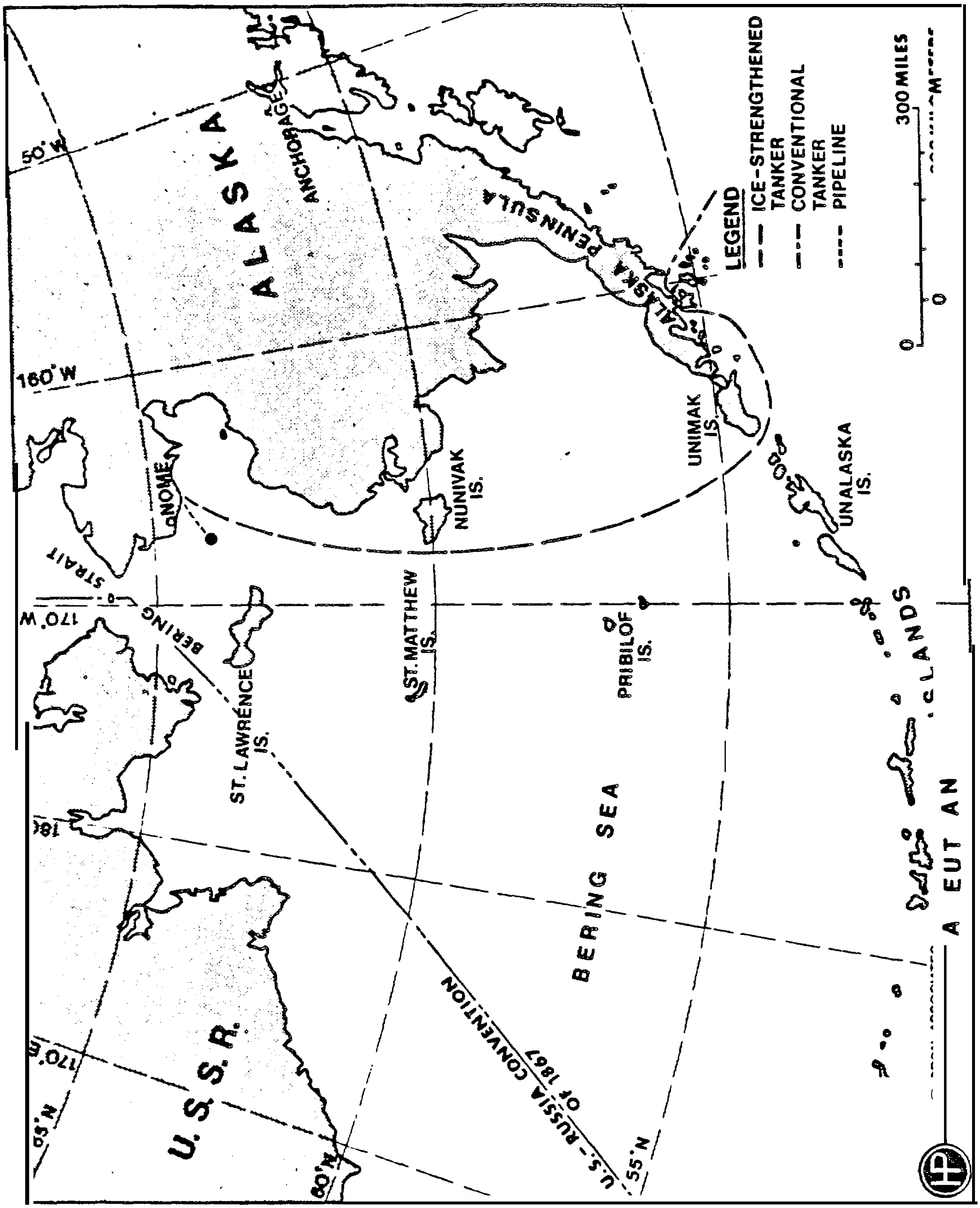

Figure 4-3. Scenario 1, Transportation Alternative B.

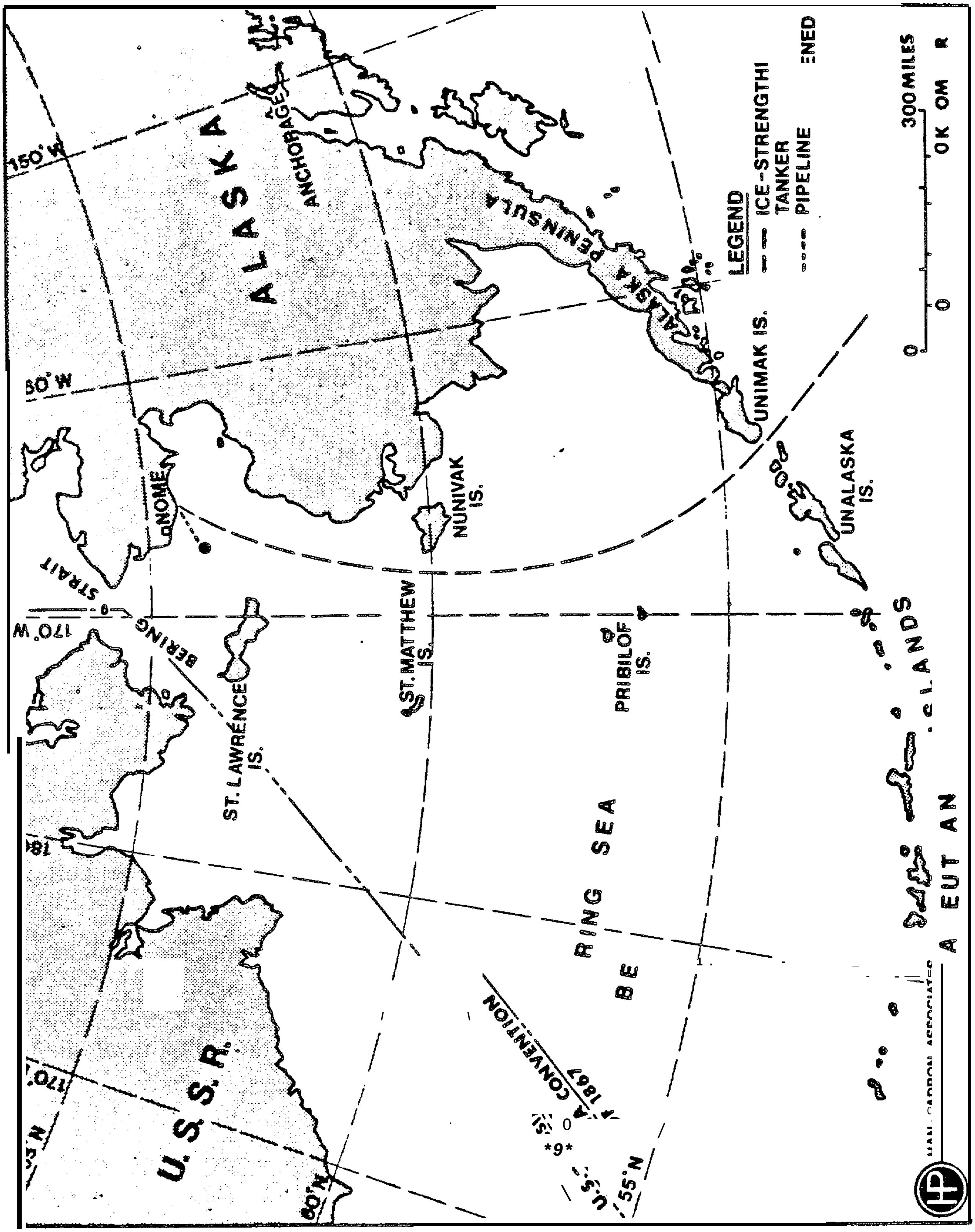

Figure 4-4. Scenario 1, Transportation Alternative C.

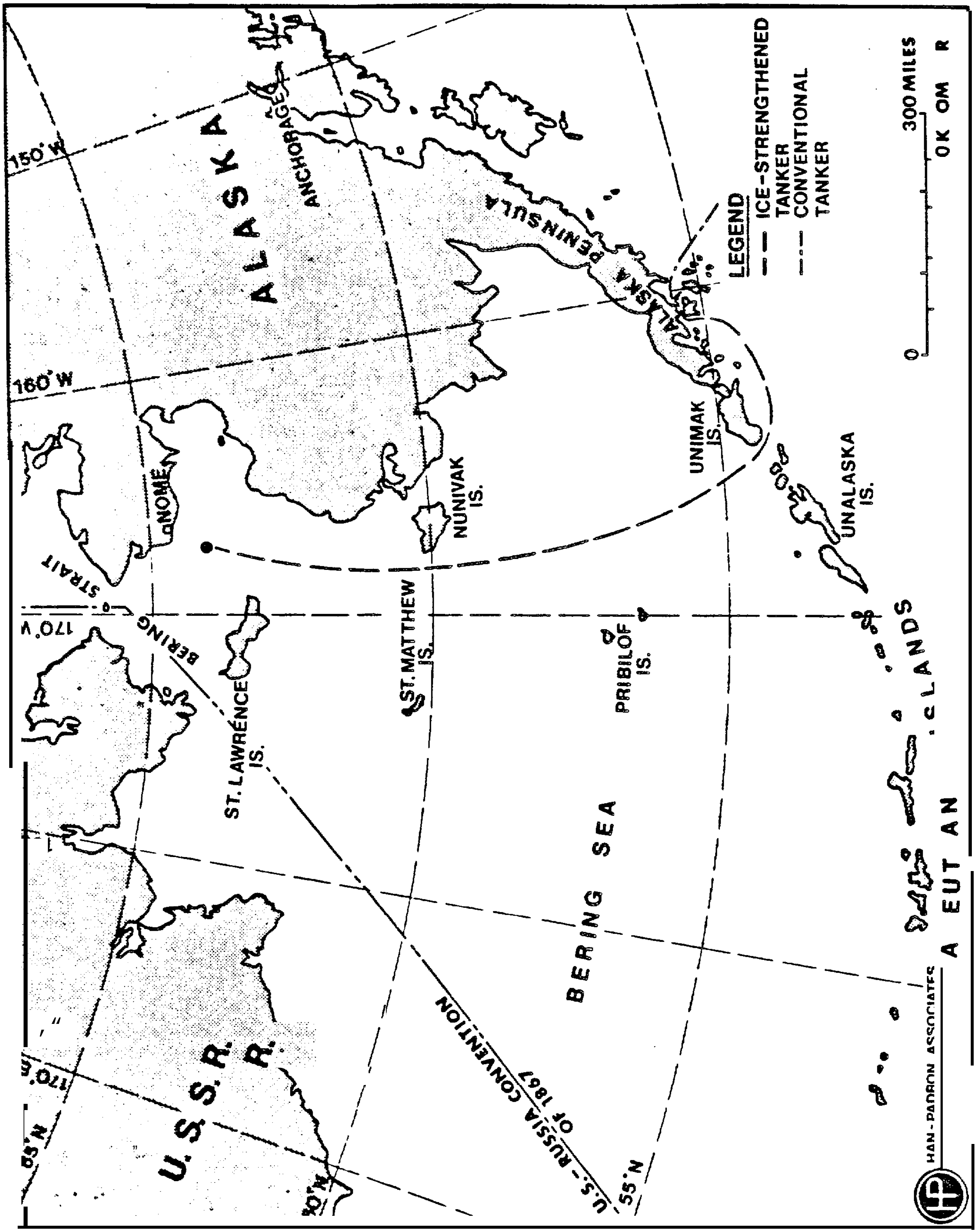

Figure 4-5. Scenario 1, Transportation Alternative D.

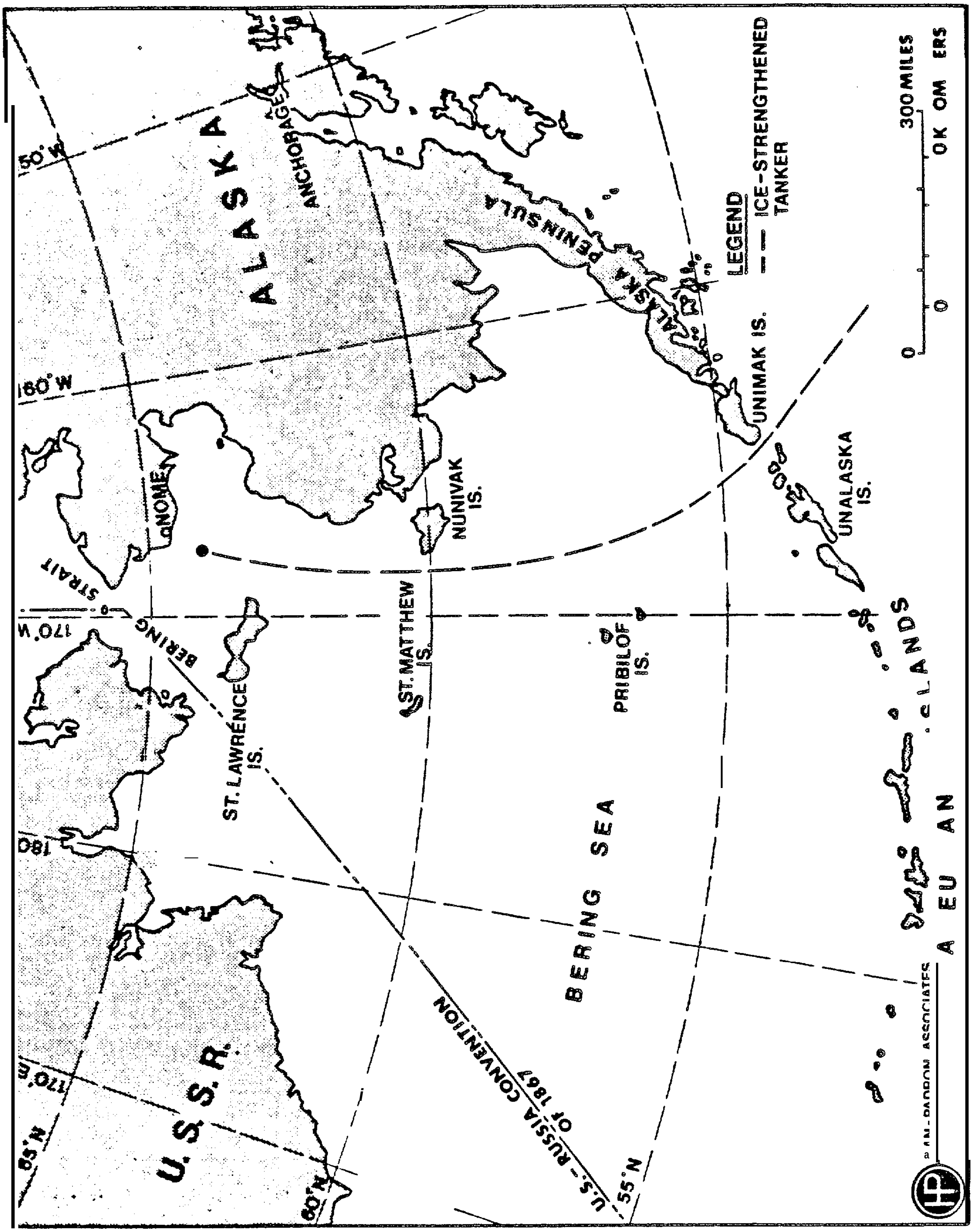

Figure 4-6. Scenario 1, Transportation Alternative E.

Alternative 1E

Offshore loading of ice-strengthened tanker operating directly to the U.S. West Coast (see Figure 4-6).

4.3 CRUDE OIL DESTINATIONS

For each of the transportation alternatives listed in Section 4.2, base case pipeline lengths and tanker route lengths that have been used in the evaluation of the alternative are listed below. When minimum and maximum lengths have been used for sensitivity analyses they are also listed. Where any likely variation in a pipeline or tanker route length was less than ten percent of the base case length, no length sensitivity analysis was performed.

	LENGTH km (mi) Base Case	Min. Case	Max. Case
Alternative 1A			
Marine pipeline	70 (43)		
Land pipeline	1125 (700)		
Conventional tanker route	3400 (2110)		
Alternative 1B			
Marine pipeline	70 (43)	30 (19)	110 (68)
Ice-strengthened tanker route	1510 (940)		
Conventional tanker route	3200 (1990)		

Alternative 1C

Marine pipeline	70 (43)	30 (19)	110 (68)
Ice-strengthened tanker route	4460 (2770)		

Alternative 1D

Ice-strengthened tanker route	1450 (900)
Conventional tanker route	3200 (1990)

Alternative 1E

Ice-strengthened tanker route	4400.(2735)

4.4 OFFSHORE LOADING TERMINAL

The offshore loading terminal for Scenario 1 consists of a rigid tower type, gravity stabilized offshore loading system, a bottom founded, gravity stabilized crude oil storage structure, a pipeline connecting the production platform to the storage structure and a pipeline connecting the storage structure to the offshore loading system. The elements of the offshore terminal are shown schematically in Figure 4-7.

Unlike Scenarios 2 and 3, the crude oil storage and tanker loading functions are in separate structures for Scenario 1. This is due to the fact that the extremely high ice loading and relatively

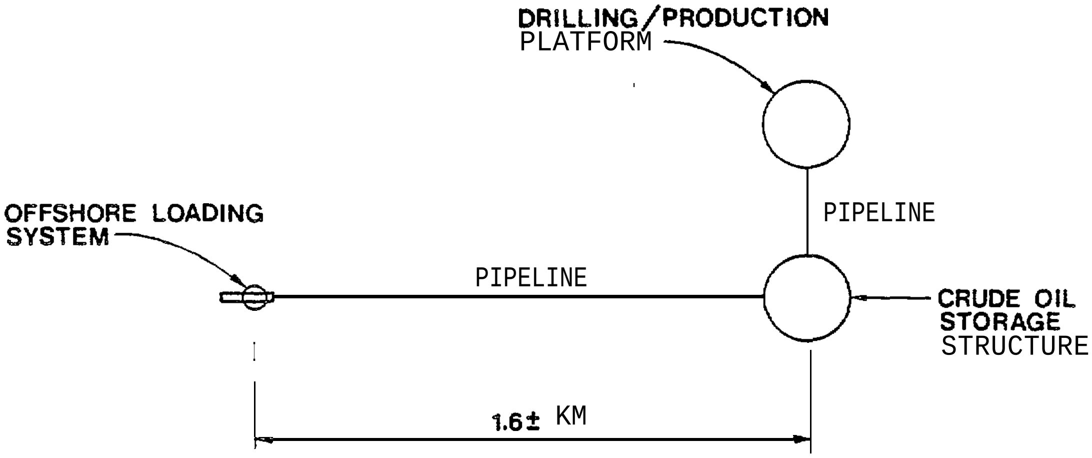

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Figure 4-7. Scenario 1 schematic layout of offshore loading terminal.

shallow water depth preclude the use of a floating storage vessel. While it is possible to mount a rotating tanker mooring and loading system on a bottom founded storage structure, it is deemed too dangerous for tankers to routinely approach and moor to such a large structure. In the event of a miscalculation during the approach, the tanker might not be able to turn sufficiently to clear the structure. Therefore, a separate tanker loading system and crude oil structure are provided. For purposes of' this study, it is assumed that the storage structure will be independent of the drilling/production structure(s). However, since the space required for oil storage is primarily below the waterline and the space required for drilling/ production operations is primarily above the waterline, it is highly probable that drilling, production and storage functions will be combined in a single structure to minimize costs, thus making transportation alternatives that utilize offshore crude oil storage more economically attractive than indicated in the following analyses.

A description of the offshore loading system is presented below based on the design philosophy described in Section 3.5.1. A description of the offshore storage structure follows. The crude oil storage capacity is based on the methodology described in Section 3.5.4. Details regarding the pipelines are provided in Section 3.5.5.

4.4.1 Offshore Loading System

The selection of the optimum concept for the offshore loading system for the Northern Bering Sea has been developed based on the factors listed in Section 3.5.1. Severe limitations caused by the extremely high ice forces and the relatively shallow water depth resulted in the selection of a rigid, gravity stabilized structure to serve as the mooring and loading facility, as shown in Figure 4-8. Other concepts that were evaluated but eventually eliminated as being less suitable include:

- buoyant articulated tower,
- catenary chain stayed articulated tower,
- dual catenary chain stabilized spar-type buoy,
- tension leg mooring, and
- shoreside causeway with dredged channel.

Ice and wave forces govern the design of the offshore loading system. Based on a preliminary sensitivity analysis, a variation in tanker size, within the range of sizes considered in this study, was found to negligibly influence the cost of the facility. Therefore, an average tanker size of 150,000 DWT was assumed and a detailed sensitivity analysis for tanker size omitted. Section 3.2 describes the procedures for the calculation of environmental forces on the structure and the specific environmental design criteria are listed in Section 4.1.

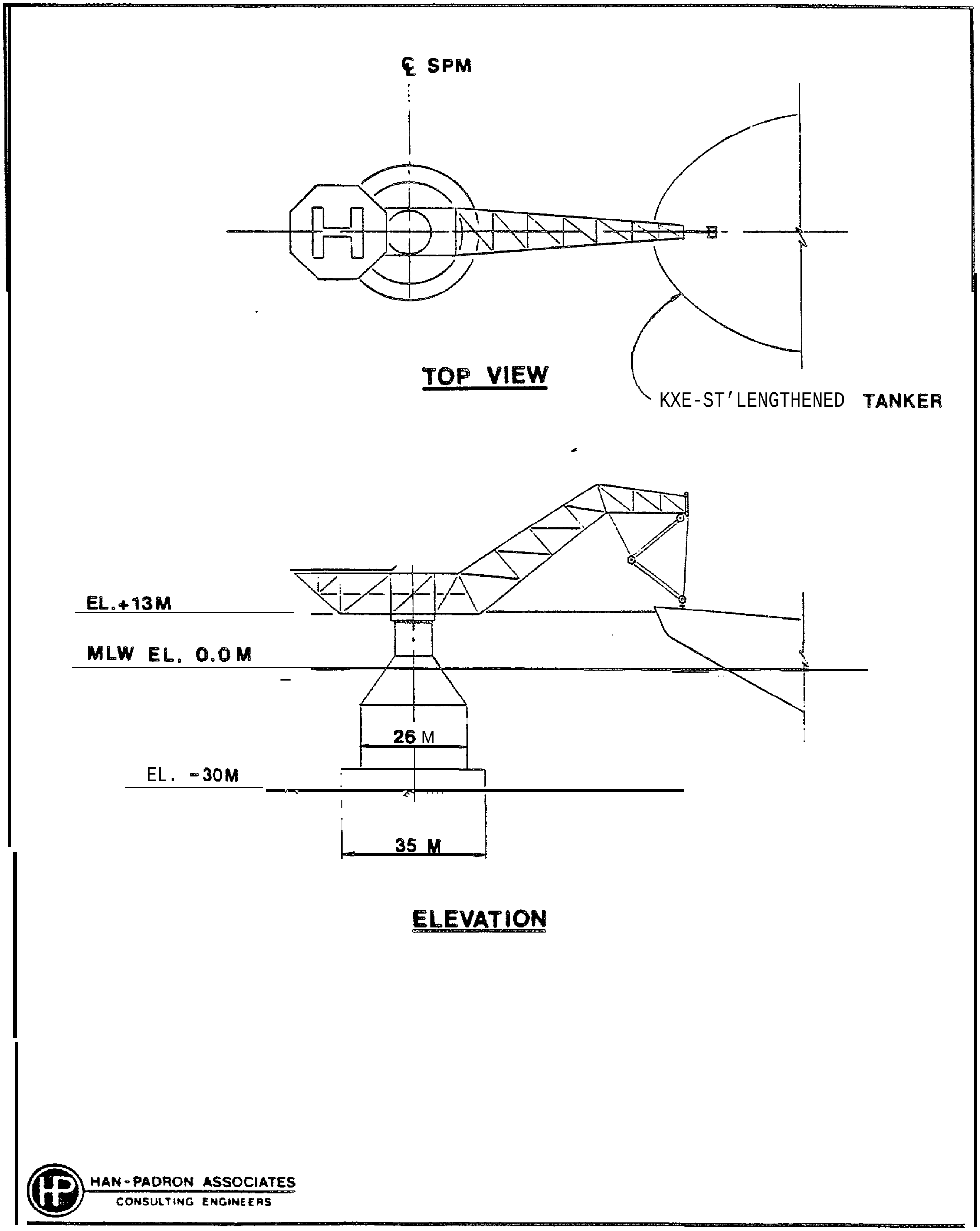

Figure 4-8. Scenario 1 offshore loading system.

Ice forces on the system include breaking and clearing components on the structure and the moored tanker. Design criteria have been established which require the mooring structure to resist 100 year recurrence interval ice features while the berth is vacant. When the berth is occupied, the mooring structure is required to resist the forces from 1 year recurrence interval ice features acting on both the structure and the moored tanker. During exceptionally heavy ice conditions, or when it is determined that interaction-with greater than 1 year ice ridges is likely, tankers will be required to cease loading and disconnect from the mooring.

Since the peak breaking and clearing ice force components do not occur simultaneously, the governing ice force condition on the system occurs with 1 year sheet ice acting on the tower and a 1 year pressure ridge clearing a moored tanker. The maximum force varies by less than 3 percent for tower cone angles between 45 and 55 degrees. Therefore, the 55 degree geometry was selected to reduce the overall size of the structure, thus reducing the wave forces acting on it. For this configuration, the total lateral force for the governing ice condition is approximately 4,300 t (9,500,000 lb), 3,800t (8,400,000 lb) of which is acting on the moored tanker. By comparison, the 100 year ice ridge imposes a lateral force of approximately 3,300 t (7,300,000 lb). The wave loading, although not a governing condition in the design of this structure, generates a substantial lateral force, on the order of 4,100 t (9,000,000 lb), and an almost equal vertical force. The maximum vertical wave force on the structure occurs out of phase with the maximum lateral force by one-fourth the wave length.

The development of a system to moor the tanker to the tower will require special attention. The 3,800 t (8$4009000 lb) force exerted by the ice on the tanker must be transferred to the tower by the mooring hawsers. This force is an order of magnitude higher than maximum mooring hawser forces at existing offshore loading systems. If, for example, three grommet type hawsers are used, each must have a breaking strength of approximately 2,600 t (5,700,000 lb), requiring the use of 180 mm (7 in.) diameter wire rope or 2LI0 mm (8 in.) diameter kevlar rope. These sizes are well above sizes normally available. Care must also be exercised in the arrangement of the hawsers and detailing of the hawser connections to ensure that the load is reasonably equally distributed among the three l·nes. During open water season, the special ice season mooring hawser system could be replaced with a more conventional nylon hawser system

The offshore loading system consists of a concrete base and tower with a prefabricated steel superstructure consisting of the turntable, mechanical rotation and piping systems, living quarters, heliport and trussed gantry structure. The system is ballasted with an iron ore material and most of the remaining submerged portion of the tower is ballasted with seawater to maintain stability against overturning and sliding. The conical shaped ice-breaking tower section and the 9 m (30 ft) diameter upper cylindrical section are heavily reinforced for local ice pressures Up to 6.2 mPa (900 psi). The increased base diameter is required to preclude bearing pressure failure of the foundation soil.

The slope and vertical extent of the conical section at the waterline has been selected to insure adequate breaking and clearing of all design ice features in the study area. The concrete surface is covered with metal plating to protect the concrete from abrasive wear and to lower the coefficient of friction between the ice and structure. It is anticipated that for the base case water depth and structure diameter, ice rubble pileup around the structure will not occur. However, for shallower water depths, pileup may occur and interfere with tanker approach to the mooring structure. Further study of the pileup phenomenon, including model tests, will be required prior to design of this type of structure in water depths less than approximately 20 m (65 ft).

The submerged portion of the structure is radially subdivided into watertight compartments that are either ballasted with iron ore or flooded with seawater. The base of the structure may be partially embedded in the soil depending on site specific water depth and soil characteristics. The bottom surface of the base is formed in a grid pattern to function as soil shear keys. Shear keys insure that the sliding failure plane lies within the foundation soil mass rather than between the soil and structure.

The trussed superstructure contains a heliport and provides a gantry for the support of loading and mooring operations. Enclosed, heated walkways and general work areas are provided throughout the superstructure. Personnel quarters, power generation and other support facilities are also located within the superstructure.

Capital cost for the offshore loading system is presented in Figure 4-9 versus water depth. Variation in water depth influences the wave forces on the structure but does not affect the design ice forces. The variation in capital cost is a direct result of the variation in fabrication cost of the tower and the quantity of ballast material required.

The sensitivity case alternative soil condition in the northern study area is a slightly less favorable foundation material for the offshore loading structure and will result in an increase in cost of approximately 4 percent over the base case structure cost. The increased cost results from increased concrete base structure dimensions.

Annual operating and maintenance cost for the offshore loading system is estimated to be approximately $4.0 million. The manpower required to operate and maintain the system is estimated to be 10 men times a rotation factor of two.

The berth availability rate, as defined in Section 3.5.2, has

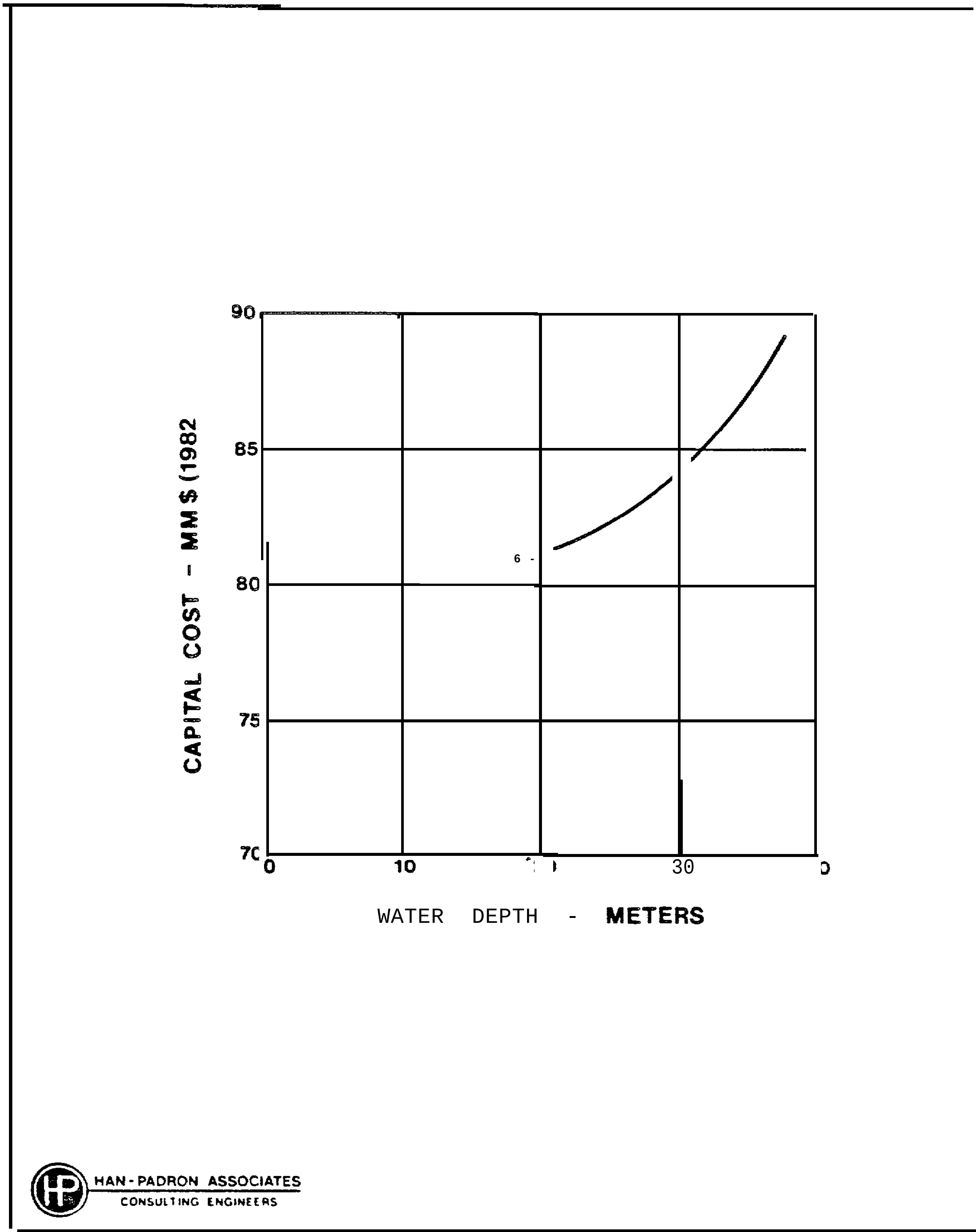

Figure 4-9. Scenario 1 offshore loading system capital cost versus water depth.

been established for the Scenario 1 offshore loading system based on the criteria listed in Section 3.5.2, and summarized as follows:

- Ice and visibility conditions will not limit mooring operations.
- Mooring operations will take place in seas with a significant wave height of 4.0 m (13 ft).
- Unscheduled maintenance causes 5 percent maintenance downtime.

The average frequency of occurrence, over the worst three consecutive months, of significant wave heights exceeding 4.0 m (13 ft), based on wave height threshold data contained in "Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska" (Brewer et al. 1977), is approximately 5 percent. Allowing for 5 percent unplanned maintenance downtime, the berth availability rate for this scenario is 90 percent.

4.4.2 Offshore Storage System

The offshore crude oil storage structure selected for Scenario 1 is shown in Figure 4-10. The shallow water depth and heavy ice conditions necessitate the use of a large diameter, gravity stabilized, concrete structure. A seawater displacement system is used to balance internal and external pressures and to prevent the structure from lifting off the seabed as the stored crude oil is discharged. The concept as shown in the figure is sized for a

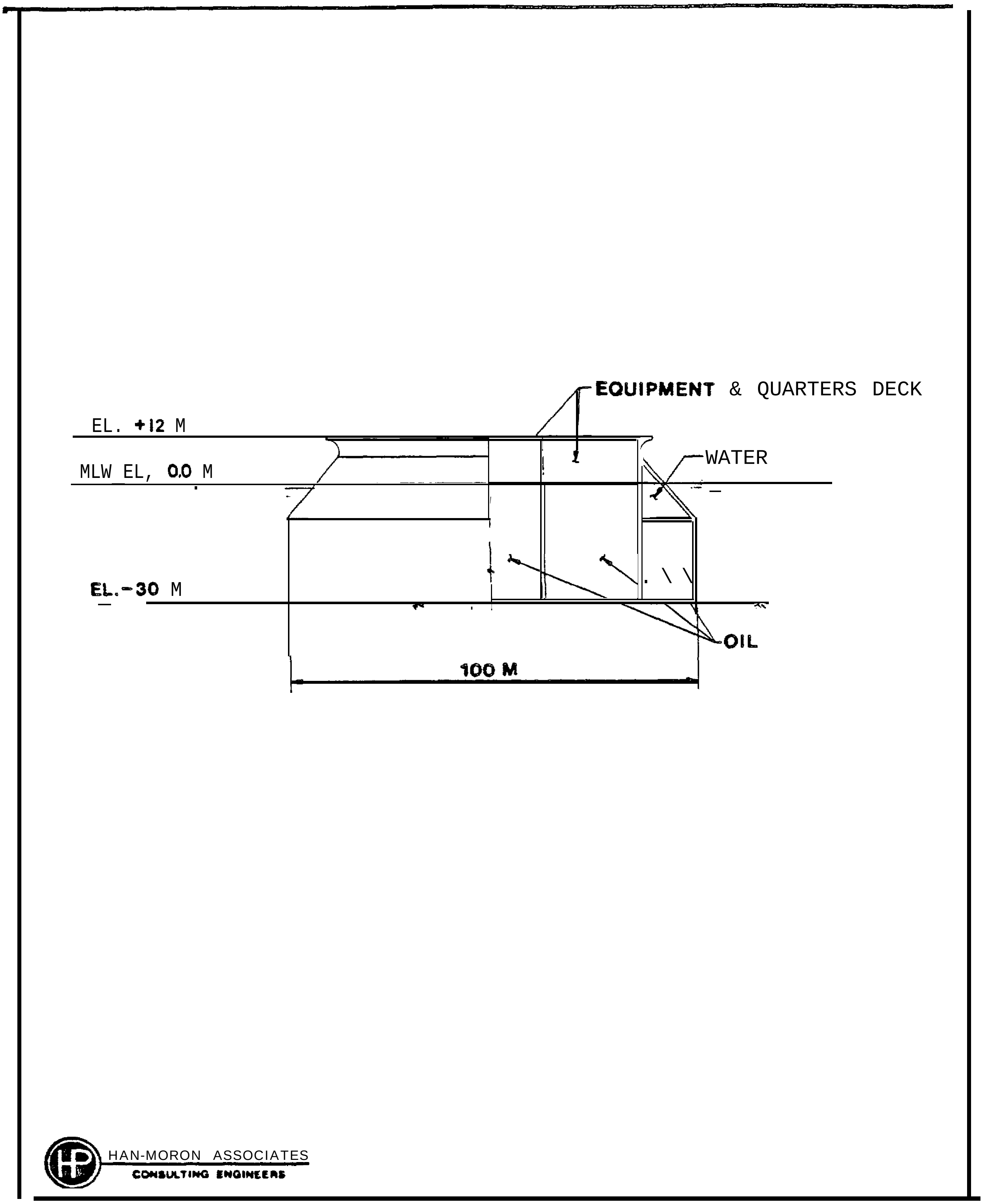

Figure 4-10. Scenario 1 one million barrel offshore storage structure.

storage capacity of 1.0 million barrels and designed for the environmental criteria listed in Section 4.1. Section 3.2 describes the procedures used for calculation of the environmental forces on the structure.

The storage structure, located in the base case water depth of 30 m (100 ft) and with a storage capacity of 1.0 million barrels, is 100 m (330 ft) in diameter with the top deck located 12 m (39 ft) above mean low water level. The structure is conically shaped at the waterline to aid in breaking and clearing ice features and the outer perimeter of the upper deck is shaped-to function as a deflector shield and prevent ice ride-up onto the structure.

Ice and wave forces govern the design of the storage structure. Ice forces consist of the breaking and clearing component mechanisms associated with the maximum sheet ice and pressure ridge features. The governing condition for ice force on the large diameter structure is a result of the 100 year rafted ice sheet breaking and clearing across the entire width of the structure. For this condition, and a cone angle of 50 degrees, the lateral force on the structure is 4,400 t (9,700,000 lb) with a vertical downward force of 3,400 t (7 ,600,000 lb). By comparison, the lateral force required to fail the 100 year design pressure ridge is 2,700 t (6,000,000 lb). The global ice forces, however, are lower than the maximum 100 year wave load which governs the overall stability design of the structure. Ice strength and feature dimensions only govern the local design of the conical surface of the structure, which requires heavy reinforcing for ice pressures up to 6.2 mPa (900 psi). Without the conical ice breaking shape, maximum global ice loads would surpass the maximum wave loads, which consist of a lateral force of approximately 23,000 t (50,000,000 lb) combined with a vertical force of approximately 5,000 t (11,000,000 lb), The sliding mode of stability failure governs the design of the structure for both the base case and alternative case soil conditions.

The caisson-type structure is constructed of concrete and is internally subdivided into oil storage, seawater ballast, equipment and quarters chambers. Equipment and quarters facilities are located inside the storage structure for protection from the harsh environment. The bottom of the structure is formed in a grid pattern to function as soil shear keys and to insure that the shear failure plane is located within the soil mass and not at the unpredictable soil/structure interface. The conically shaped section has a vertical extent sufficient to fail and clear all design ice features. The external conical surface is clad with steel plate to eliminate abrasion of the concrete by the continuous ice action and to lower the ice/structure friction coefficient.

Capital cost for the offshore storage structure, with a storage capacity of 1.0 million barrels, is presented in Figure 4-11 versus water depth. The increase in cost with decreasing water depth follows from the fact that as the submerged volume of the structure

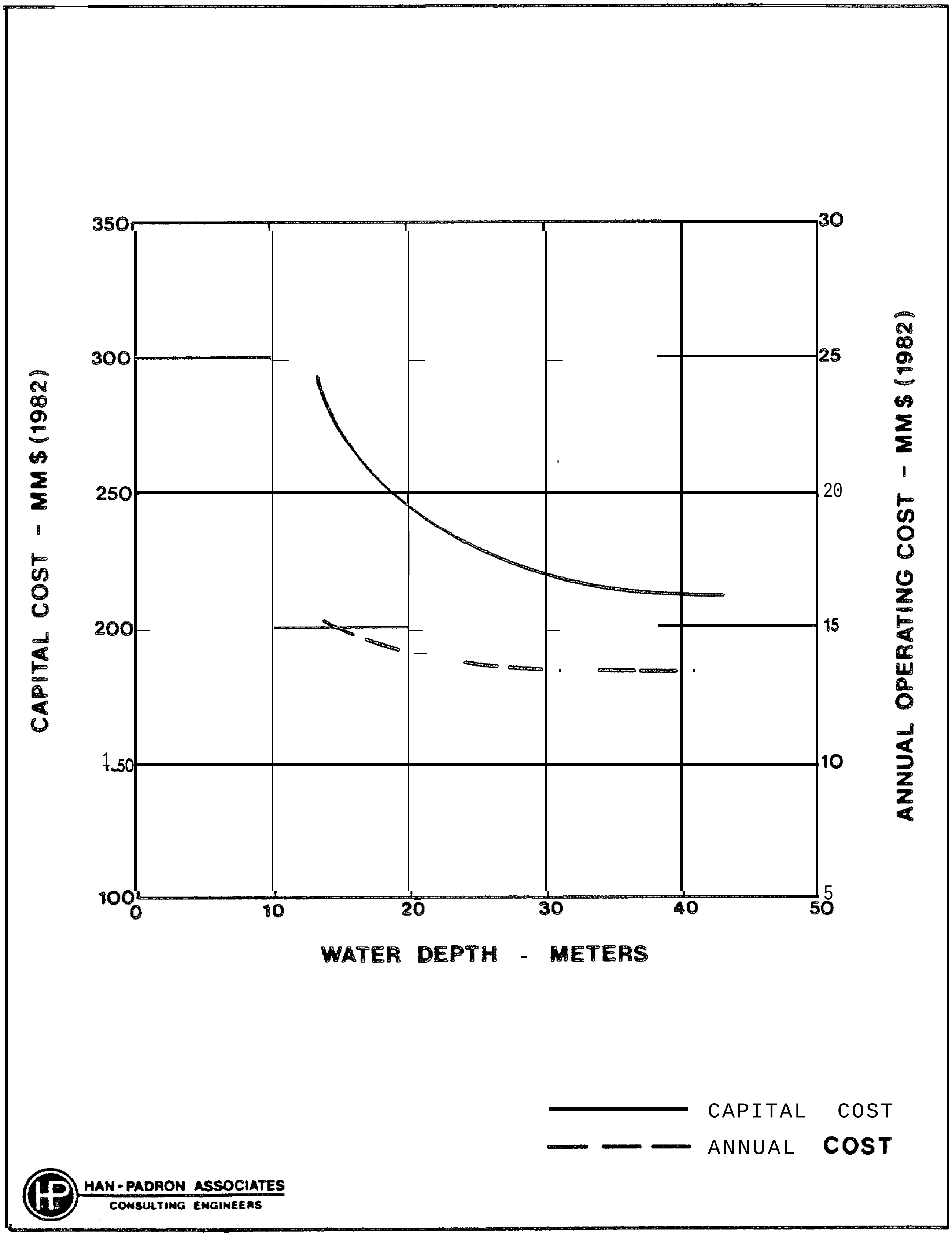

Figure 4-11. Scenario 1 one million barrel offshore storage structure capital and annual costs versus water depth.

remains constant, shallower water depths result in an inefficient structural configuration and a substantial wasted volume above the water line. This inefficient configuration results in increased capital cost. In shallow water depths an alternate storage system would be more suitable.

The sensitivity case soil condition, being slightly less favorable for gravity-type structures, requires less than a 3 percent increase in the capital cost of the storage structure over the base case cost. The increase in cost results from the addition of solid ballast to maintain the structure's sliding stability.

The capital cost for the offshore storage structure versus storage capacity is given in Figure 4-12 for the base case soil and water depth conditions. The rapid increase in cost with storage capacity is a result of not only the increased structure dimensions but also the additional ballast required to maintain stability against the increased wave loads on the structure.

As crude oil is withdrawn from the structure, seawater is allowed to enter to maintain an essentially balanced internal and external pressure and to prevent the structure from lifting off the seabed. When crude oil is being pumped into the storage chambers, the internal seawater is displaced to a ballast water treatment facility located in the upper section of the structure. The treated ballast water is then discharged into the sea.

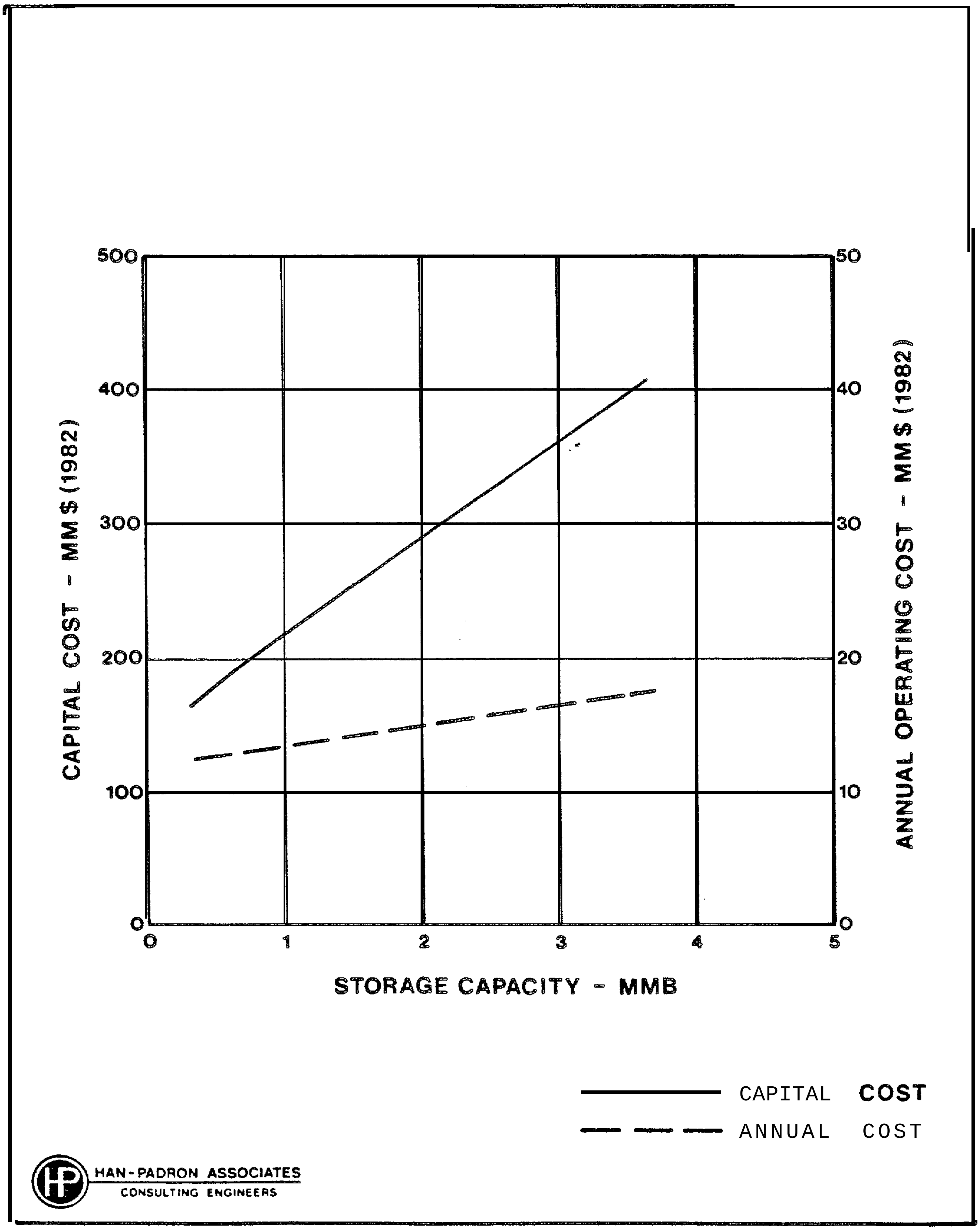

Figure 4-12. Scenario 1 offshore storage structure capital and annual costs versus storage capacity.

The annual operating and maintenance cost for the offshore storage structure has been estimated on the basis of the manpower cost plus 2.5 percent of the capital cost. The annual cost is shown in Figure 4-11 versus water depth for 1.0 million barrel storage capacity and in Figure 4-12 versus storage capacity for a water depth of 30 meters.

The manpower required to operate and maintain the offshore storage system is estimated to be 40 men times a rotation factor of two.

4.5 NEARSHORE LOADING TERMINAL

The nearshore loading terminal for Scenario 1 consists of a rigid tower type offshore loading system, onshore storage facilities, and a pipeline connecting the storage facilities to the offshore loading system. Since the environmental conditions, degree of exposure, and water depths for the tanker loading structure are similar for both the Scenario 1 offshore and nearshore terminals, the same basic structure has been selected for both terminals. Refer to Section 4.4.1 for a complete discussion of the offshore loading system. The only significant difference between the loading systems at the two types of terminals is that at the offshore terminal the water depth is established by the location of the drilling/production platform(s) and will be deeper than for the nearshore terminal where the water depth is determined by assuring adequate underkeel clearance throughout the tanker maneuvering area.

Due to the shallow water depth selected for the mooring structure, it is installed in a 5 m (16 ft) hole dredged in the seabed. This results in the top of the structure base being level with the surrounding 'seabed, insuring that a tanker coming close to the structure will not contact the base before it contacts the structure's fender system. Placing the structure in a dredged hole also increases the allowable soil bearing capacity and lateral resistance, thus decreasing the overall dimensions of the structure.

The capital cost of the loading system for the nearshore terminal is shown in Figure 4-13 as a function of the size of the tankers that will be using the terminal. The annual operating and maintenance cost for the loading system is estimated to be $4.0 million. The manpower required to operate and maintain the loading system is estimated to be 10 men times a rotation factor of two.

The onshore storage facilities are described in Section 3.5.4 and the pipelines are described in Section 3.5.5.

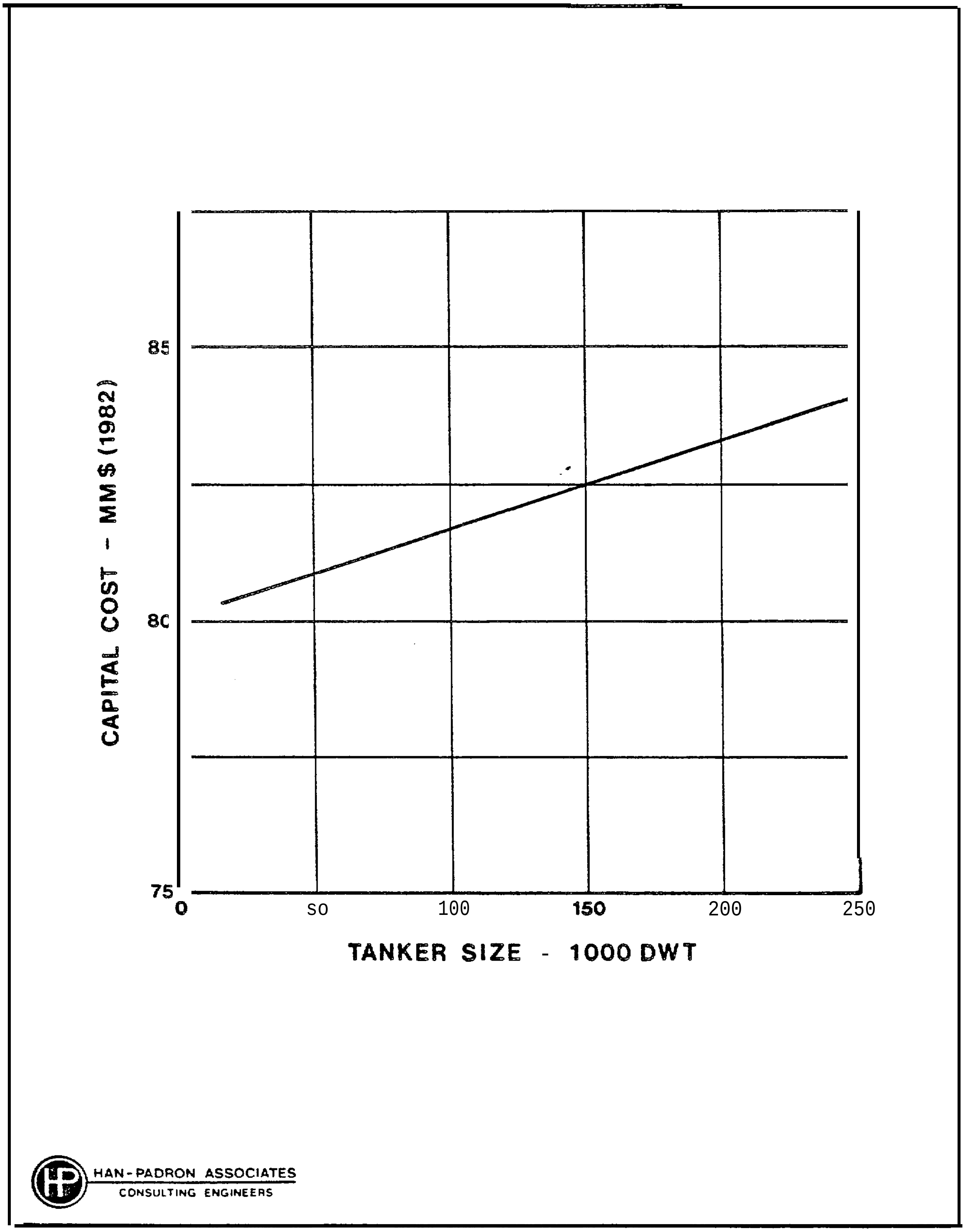

Figure 4-13. Scenario 1 nearshore loading system capital cost versus tanker size.

4.6 OPTIMIZATION OF TRANSPORTATION ALTERNATIVES

The optimum size/number/capacity of each of the transportation system elements of each of the five Scenario 1 alternatives, based on the base case scenario parameters, are listed in Table 4-1. The optimum size and number of ice-st lengthened and conventional tankers have been developed as described in Section 3.4.1. The ice class of escort icebreakers has been developed as described in Section 3.4.4. The berth occupancy rates and number of berths for each type of terminal have been developed as described in Section 3.5.3. The optimum storage capacity for each type of terminal has been developed as described in Section 3.5.4. The loading pipeline diameter has been developed as described in Section 3.5.5. The marine pipeline diameter and length have been developed as described in Section 3.6 and the land pipeline diameter and length as described in Section 3.7.

4.7 COMPARISON OF TRANSPORTATION ALTERNATIVES

Each Scenario 1 crude oil transportation alternative has been compared on the basis of total cost over the life of the reservoir, based on a discount rate of 8 percent, as described in Section 4.7.1. The various alternatives have also been compared based on factors other than cost, such as, construction logistical and timing problems, environmental factors and reliability, as described in Section 4.7.2.

TABLE 4-1

SCENARIO 1 OPTIMUM TRANSPORTATION SYSTEM ELEMENTS

TRANSPORTATION ELEMENT	ALTERNATIVE 1A	1B	1C	1D	1E
Ice-strengthened Tankers					
Ice Class	-	4	4	4	4
Size (MDWT)	-	85	169	85	169
Number	-	2	2	2	2
Icebreakers					
Ice Class	-	5	5	5	5
Number	-	2	2	2	2
Conventional Tankers					
Size (MDWT)	151	127	-	127	
Number	2	2	-	2	
Offshore Loading Terminal					
Berth Occupancy Rate (%)	-		-	26	17
Number of Berths	-		-	1	1
Storage Capacity (MMB)	-		-	0.9	1.5
Loading Ppl Dia (in.)	-		-	34	40
Nearshore Loading Terminal					
Berth Occupancy Rate (%)	13	26	17		
Number of Berths	1	1	1		
Storage Capacity (MMB)	1.5	0.9	1.5		
Loading Ppl Dia (in.)	40	28	46		
Transshipment Terminal					
Berth Occupancy Rate (%)	-	22		22	
Number of Berths	-	2		2	
Storage Capacity (MMB)	-	1.6		1.6	
Load./Unload. Ppl Dia (in.)	-	36		36	
Marine Pipeline					
Diameter (in.)	18	18	18		
Length (km)	70	70	70		
Land Pipeline					
Diameter (in.)	16				
Length (km)	1125				

4.7.1 Cost

The total cost of the crude oil transportation system over the life of the reservoir, which has been assumed to be 15 years, has been calculated for each alternative and the results are presented in Tables 4-2 through 4-6. The tables show the capital cost for each major transportation system element, the characteristics of which are listed in Table 4-1. For each element, the annual operating cost, during a peak production year, is also shown, as is the manpower required to operate the element. The manpower figures presented are the crew size times a "shift factor" and times a "rotation factor." Tanker crews are not included.

The present value of the total life cycle cost is listed at the bottom of the tables. These figures are based on constant January 1982 dollars and an 8 percent discount rate. The effect. of taxes or royalties is not included.

To obtain the average transportation cost (ATC) of the crude oil, on a per barrel basis, the present value of total cost is divided by the total volume of oil produced over the 15 year life of the reservoir.

Transportation alternative 1E results in the lowest ACT for Scenario 1.

TABLE 4--2

TRANSPORTATION ALTERNATIVE 1A

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	---	---	Excl
ICEBREAKERS	---	---	---
CONVENTIONAL TANKERS	274	28	Excl
OFFSHORE LOADING TERMINAL	---	---	---
NEARSHORE LOADING TERMINAL	330	19	120
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	91	3	---
LAND PIPELINE	5089	175	Excl
TOTAL	5784	225	120

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 7870

AVERAGE TRANSPORTATION COST PER BARREL = $ 18.36

TABLE 4-3

TRANSPORTATION ALTERNATIVE 1B

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	366	36	Excl
ICEBREAKERS	220	26	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	---	---	---
NEARSHORE LOADING TERMINAL	336	18	120
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	90	3	...
LAND PIPELINE	...	---	...
TOTAL	1689	132	360

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2880

AVERAGE TRANSPORTATION COST PER BARREL = $ 6.71

TABLE 4-4

TRANSPORTATION ALTERNATIVE 1C

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	460	46	Excl
ICEBREAKERS	220	26	100
CONVENTIONAL, TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL	...	---	---
NEARSHORE LOADING TERMINAL	433	19	120
TRANSSHIPMENT TERMINAL	...	---	---
MARINE PIPELINE	90	3	...
LAND PIPELINE	---	---	---
TOTAL	1203	94	220

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2050

AVERAGE TRANSPORTATION COST PER BARREL = $ 4.78

TABLE 4-5

TRANSPORTATION ALTERNATIVE 1D

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	366	36	Excl
ICEBREAKERS	220	26	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	323	18	100
NEARSHORE LOADING TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	1586	129	340

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2750

AVERAGE TRANSPORTATION COST PER BARREL = $ 6.41

TABLE 4-6

TRANSPORTATION ALTERNATIVE 1E

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	460	46	Excl
ICEBREAKERS	220	26	100
CONVENTIONAL TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL	385	19	120
NEARSHORE LOADING 'TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	1065 .-	91	220

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 1880

AVERAGE TRANSPORTATION COST PER BARREL = $ 4*39

4.7.2 Other Factors

There are a number of factors, other than costs, which may affect the selection of a crude oil transportation system for Scenario 1. These factors are difficult, if not impossible, to quantify and are described below.

a) Construction Time and Logistics

Construction time for each alternative is approximately four years. Therefore, there is no preference for a particular alternative on this basis.

For offshore terminal alternatives, most fabrication work. is performed off-site and the minimal amount of on-site work required can be supported from the construction camp set up for drilling/production construction operations, Nearshore and transshipment terminal construction activities will probably require the establishment of a construction camp to support tank farm and long marine pipeline construction.

The construction of a land pipeline will also require a substantial support base.

b) Reliability

Tanker operations that require traveling through open water only, rather than through ice fields, are preferable because travel time is more predictable and the chance of getting stuck in unforeseen severe ice conditions is eliminated Routine tanker operation through ice is unproven, but there is ample evidence that it is practical for this scenario. Considering this factor, Alternative 1A is preferable to the other four alternatives.

For Scenario 1 there is virtually no difference between offshore loading and nearshore loading. In both cases the loading structure is the same and the degree of exposure of the tanker to the weather is almost the same. The exception is Alternative 1A in which the nearshore loading terminal utilizes a conventional loading berth in a protected location. The technology of loading offshore in a severe ice environment is untried but there is every indication that it is practical. Considering these factors, Alternative 1A is preferable to the other four alternatives and there is no difference among the four.

c) Environmental Considerations

From the point of view of minimizing disturbance of the environment, offshore storage is preferable to onshore storage. Onshore storage requires development of a large land area and the construction of a pipeline in a trench through the nearshore and surf zone. Operating personnel for offshore storage are quite isolated from existing communities. Onshore storage requires a large amount of on-site construction personnel and equipment while most construction activities for offshore storage take place off-site. Considering these factors, Alternatives 1D and 1E are preferable to the other three alternatives.

The greater number of times the crude oil is loaded and unloaded en route to the refinery, the greater is the risk of a spill and subsequent damage to the environment. Therefore, alternatives that do not require a transshipment terminal (1A, 1C and 1E) are preferable to those that do (1B arid 1D).

The construction of a long land pipeline, with its access road and booster stations, would be quite disturbing to the environment and would probably encounter the most permit and regulatory difficulty. Considering this factor, Alternative 1A is undesirable compared with the other alternatives.

d) Other Considerations

In accordance with the terms of reference for this study the alternatives that provide for offshore storage have been based on the assumption that the crude oil storage structure will be separate from the drilling/production structure(s). However, the storage structure is a very large, fixed, gravity structure that could' readily be modified to support drilling operations and/or production equipment. By combining drilling, production and storage functions in a single structure, total capital costs, and consequently the ATC would be substantially reduced.

4.8 SENSITIVITY ANALYSIS

In order to evaluate the effect of variations in the scenario parameters on the conclusions regarding the optimum transportation alternative, a number of sensitivity analyses have been carried out. The parameters varied for the analyses include:

- quantity of recoverable reserves (production rate),
- crude oil properties,
- distance to shore,
- water depth, and
- geotechnical conditions.

The effects of these variations on the individual transportation elements are discussed in the sections of this report in which the elements are described. This section is concerned with the effect on the overall transportation system alternatives for Scenario 1.

Appendix B contains tables which show the capital cost, annual operating cost and manpower required for each major transportation system element, for each alternative, and for each sensitivity parameter variation. The tables also list the present value of the total life cycle cost and the average transportation cost (ATC) of the crude oil for each case. They have been developed by fixing all scenario parameters but one at the base case values and setting the one parameter at a non-base case (sensitivity) value.

4.8.1 Recoverable Reserves

The base case recoverable reserves have been defined as 500 million barrels and the sensitivity values range from 100 million to two billion barrels. All size reservoirs have been assumed to perform in the same manner, as described in Section 3.3.2, with peak production rate equal to 9.1 percent of reserves.

Figure 4-14 presents the results of the recoverable reserves sensitivity analysis in the form of average crude oil transportation cost versus peak production rate. From the figure it is obvious that the transportation cost for each of the five alternatives considered is very sensitive to the production rate. However, since the curves representing each alternative do not cross, the production rate does not affect the determination of the alternative that provides the lowest cost transportation system and Alternative 1E, offshore loading and direct shipment to the West Coast, is preferable on the basis of cost for all peak production rates considered.

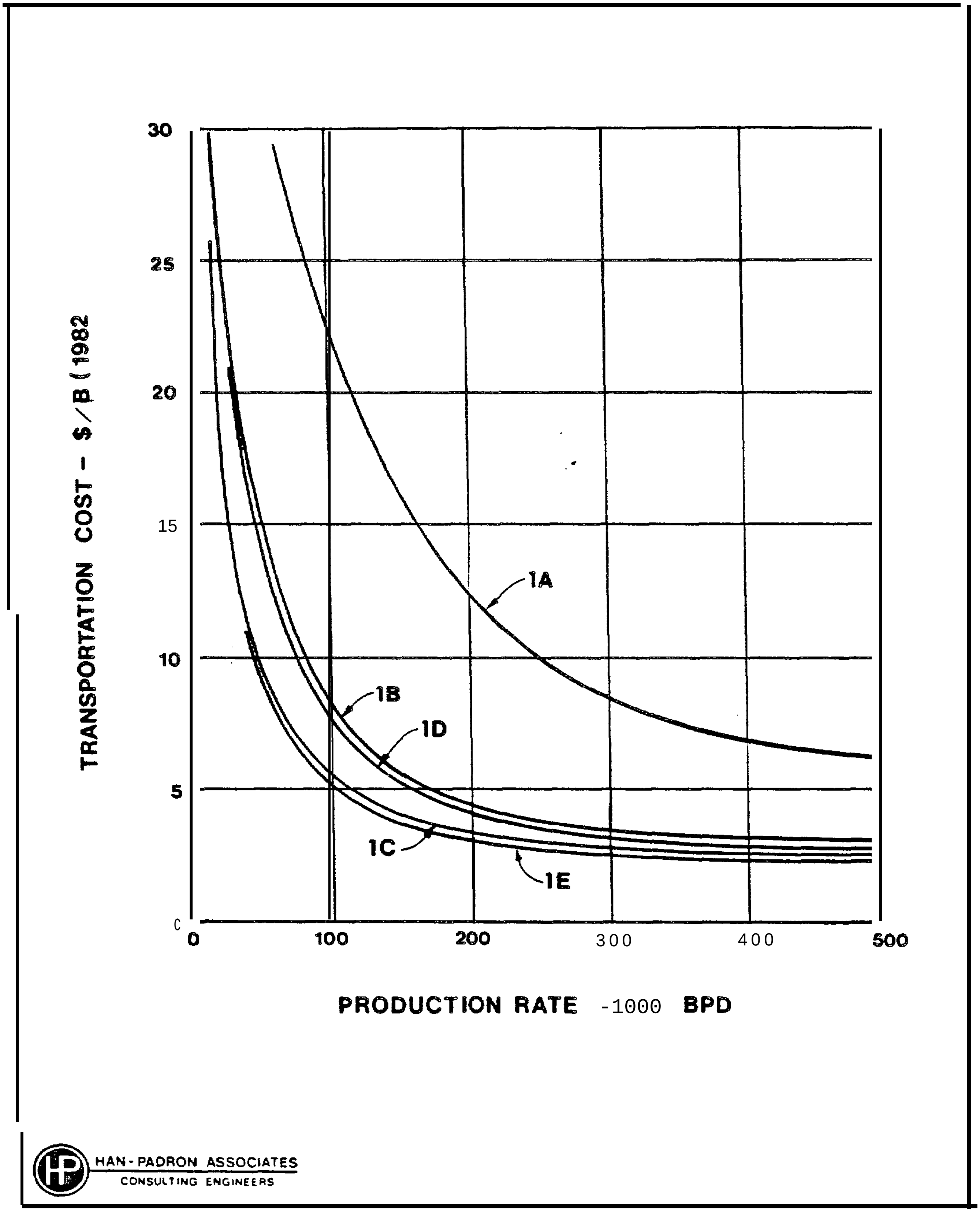

Figure 4-14. Scenario 1 crude oil transportation cost sensitivity to production rate.

4.8.2 Crude Oil Properties

The base case crude oil properties are quite suitable for transportation in either long pipelines or tankers. The sensitivity case crude oil has a relatively high pour point making pumping long distances underwater impractical. For this type of crude, offshore loading alternatives are much more attractive than alternatives that require long pipelines.

The capital cost of all alternatives considered would be higher for the sensitivity case crude. For long pipeline cases the costs would become prohibitive and no further economic analysis was conducted. For offshore loading cases, loading pipeline diameters and pumping horsepower would increase but the increase in total transportation system cost would be negligible. Alternatives requiring transshipment of the crude oil would become very unattractive because of reduction in temperature of the crude that would result from the unload"ing and loading operations.

4.8.3 Distance to Shore

Variations in the distance of the production platform from shore have virtually no effect on Alternative 1A which has an extremely long land pipeline and Alternatives 1D and 1E which have offshore storage and loading. For Alternatives 2B and 2C the variation in the average transportation cost from the base case to the maximum or minimum distance cases is less than 3.5 percent and has no effect on the conclusions reached.

4.8.4 Water Depth

The average transportation cost for Alternatives 1A, 1B and 1C are not affected by variations in water depth at the production site because these alternatives do not include an offshore terminal. The ATC for Alternatives 1D and 1E are slightly sensitive to water depth within the range considered. The maximum variation in transportation cost is less than 2.5 percent and has no effect on the conclusions reached.

4.8.5 Geotechnical Conditions

As for water depth, variations of the seabed soil parameters affect only the offshore storage and loading alternatives (1D and 1E). In both cases the ATC based on the poorer soil conditions of the sensitivity case are less than 1 percent greater than the base case ATC and have no effect on the conclusions reached.

4.9 CONCLUSIONS

On the basis of cost, transportation Alternative 1E, offshore storage and loading and direct shipment to the West Coast, is the most preferable. However, the average crude oil transportation cost for Alternative 1C, onshore storage, nearshore loading and direct shipment to the West Coast, is only 10 percent higher than for Alternative 1E and cannot be ruled out on the basis of cost. Considering the other factors as described in Section 4.7.2, and ruling out Alternative 1A because of the extremely high cost, Alternative 1E is equal to or more preferable than the other alternatives in every case. Considering the sensitivity analyses as described in Section 4.8, Alternative 1E is the most preferable on the basis of variations in crude oil properties and there is not a significant difference among all the alternatives on the basis of the other sensitivity parameters.

Therefore, for the parameters as defined, Alternative 1E is the preferred method of transporting crude oil from the Northern Bering Sea.

5.0 SCENARIO 2 - CENTRAL BERING SEA

This chapter presents the technological and cost analysis of crude oil transportation systems for the Central Bering Sea, the Navarin Basin Lease Sale area. The site selected as representative of this area is indicated in Figure 5-1. The location is based on what appears to be the center of the high interest tracts of the lease sale area and is representative of the environmental conditions in the area. All the pertinent characteristics of this scenario are defined and used in the evaluation of the transportation alternatives in the following sections. A number of the scenario parameters are varied to carry out sensitivity analyses.

5.1 ENVIRONMENTAL DESIGN CRITERIA

The background and basis for the selection of the environmental design criteria used for this study are described in Section 3.1. The specific design criteria for the Central Bering Sea scenario are listed below.

5.1.1 Ice Conditions

The properties of sea ice listed below are based on a salinity of 7 ppt, an approximate weekly minimum average air temperature of -18°C with a resultant average ice temperature of -4°C.

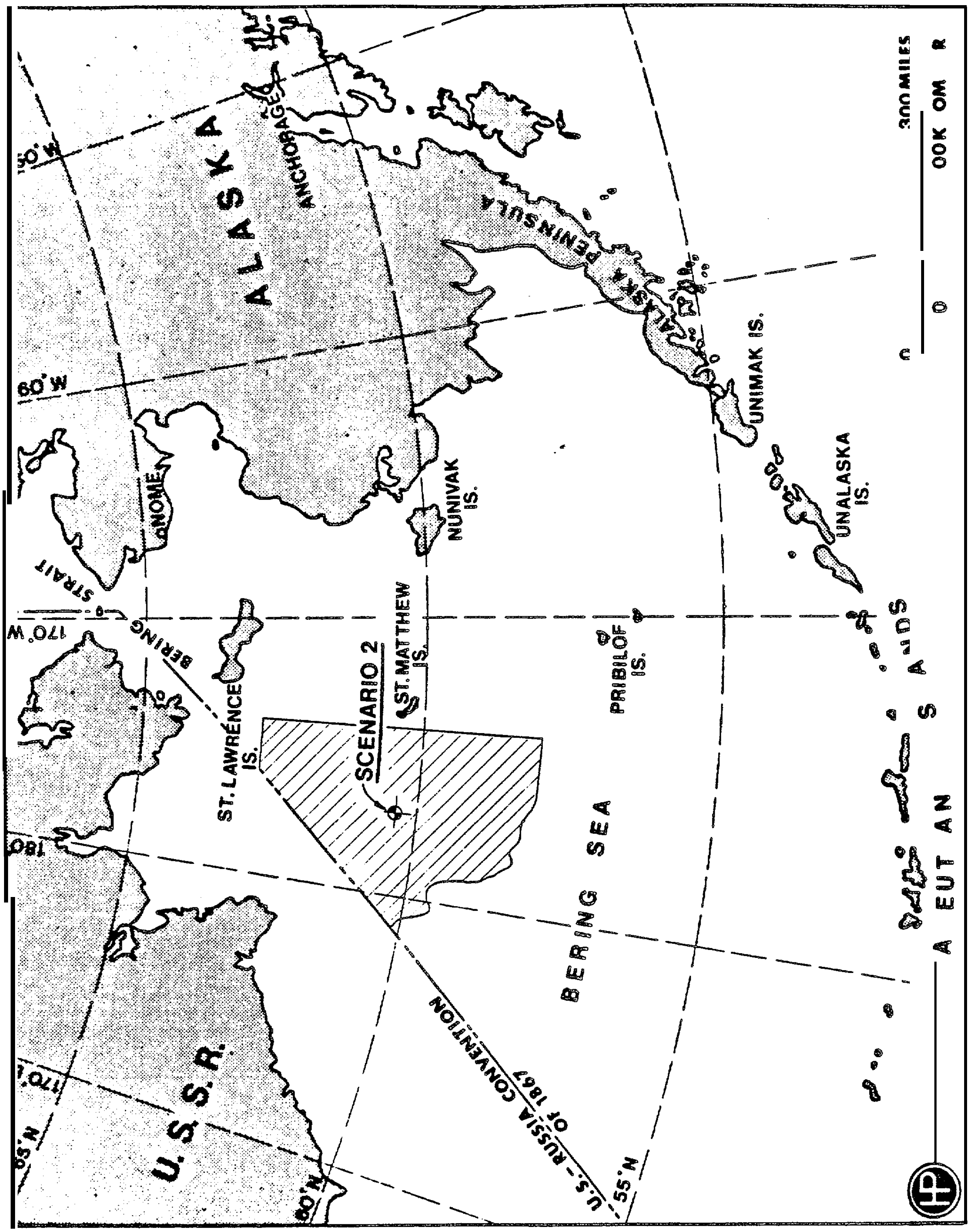

Figure 5-1. Location of Scenario 2.

a) Ice Strengths

Compressive	=	3200 kPa (460 psi)
Flexural	=	370 kPa (55 psi)
Shear	=	55(.I kPa (80 psi)

b) Ice Modulus of Elasticity and Other Properties

Modulus of elasticity	= 1,200 mPa (180,000 psi)
Poissongs ratio	= 0.33
Density	= 935 kg/cu m (58 pcf)
Coefficient of friction	
ice/steel	= 0.15
ice/concrete	= 0.30

c) Level Ice Characteristics

Average thickness	= 0.8 m (2.6 ft)
Max. rafted thickness	= 1.6 m (5.2 ft)

d) Ice Ridges

	100 Year	1 Year
Sail height, m (ft)	4.3 (14.0)	2.9 (9.5)
Keel depth, m (ft)	13.1 (43.0)	8.8 (29.0)
Depth of consolidation, m (ft)	4.9 (16.0)	3.3 (11.0)

e) Ice Coverage and Concentration

Period of greater than 0% probability of ice coverage — December 1 to July 1

	Concentration (oktas)								
	0	1	2	3	4	5	6	7	8
Frequency of Occurrence (days per year)	214	0	16	0	0	15	30	90	0

f) Ice Floe Velocity

Max. ice floe velocity = 0.75 mps (1.5 knots)

g) Superstructure Icing Rate

Max. icing rate = 2.5 cm (1.0 in.) per 3 hr

5.1.2 Waves

Max. wave height = 27 m (89 ft)

Corresponding wave period = 16 sec

Wave crest elevation above still water level = 17 m (56 ft.)

5.1.3 Water Depth

Base case = 100 m (328 ft)

Min. case = 80 m (262 ft)

Max. case = 200 m (656 ft)

5.1.4 Winds

Mean summer wind	= 5.0 to 7.5 mps (10 to 15 knots) from south through southwest
Mean winter wind	= 8 to 12.5 mps (16 to 25 knots) from north through northeast
Max. one-minute wind	= 51 mps (100 knots)
Max. three-second gust	= 62 mps (120 knots)
Max. one-hour wind	= 41 mps (80 knots)

5.1.5 Currents

Max. surface current	= 1.5 mps (3 knots)
Max. bottom current	= 0.25 mps (0.5 knots)

5.1.6 Tides/Storm Surge

Tidal range	= 0.6 m (2 ft)
Storm surge	= 1.0 m (3.3 ft)

5.1.7 Geotechnical Conditions

	Base Case	Sensitivity Analysis
Soil type	silty clay	silty sand
Friction angle, 0	0°	300
Shear strength, kPa (psf)	40 (800) @ mud line increasing @ 10 per meter of depth (60 per ft of depth)	0
Submerged unit weight, kg/cu m (pcf)	880 (55)	960 (60)

5.1.8 Seismic Conditions

API Seismic Zone	1
API Acceleration Factor	0.05

5.1.9 Meteorological Conditions

Average annual max. temperature	=	9°C (48°F)
Average annual min. temperature	=	-8°C (18°F)
Average annual precipitation	=	50 cm (20 in.)
Average annual percent frequency of occurrence of precipitation	=	20 to 35
Average annual percent frequency of occurrence of reduced visibility	=	15 to 20

5.2 DESCRIPTION OF TRANSPORTATION ALTERNATIVES

Several reasonable alternatives exist for transporting crude oil from the Central Bering Sea. Alternatives which have been discussed in previous studies, even if not considered practical, are included to provide a uniform basis for comparisons. The alternatives considered include:

Alternative 2A

Marine pipeline to a nearshore terminal on St. Matthew Island, ice-strengthened shuttle tanker to an Alaska

Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 5-2).

Alternative 2B

Marine pipeline to a nearshore terminal on St. Matthew Island and ice-strengthened tanker to the U.S. West Coast (see Figure 5-3).

Alternative 2C

Marine pipeline to a nearshore terminal on St. Paul Island, ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 5-4).

Alternative 2D

Marine pipeline to a nearshore terminal on St. Paul Island and ice-strengthened tanker to the U.S. West Coast (see Figure 5-5).

Alternative 2E

Offshore loading of ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 5-6).

Alternative 2F

Offshore loading of ice-strengthened tanker operating directly to the U.S. West Coast (see Figure 5-7).

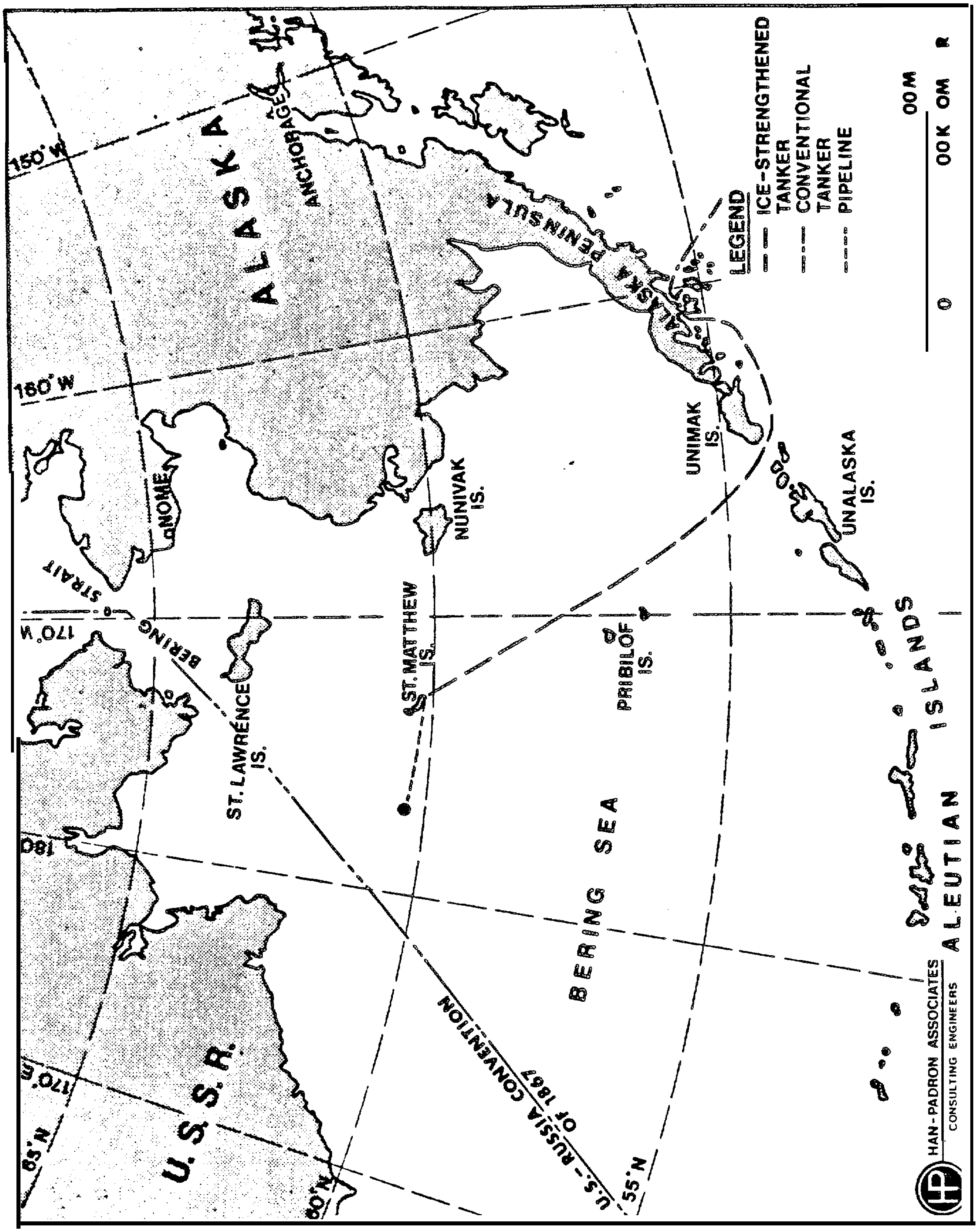

Figure 5-2. Scenario 2, Transportation Alternative A.

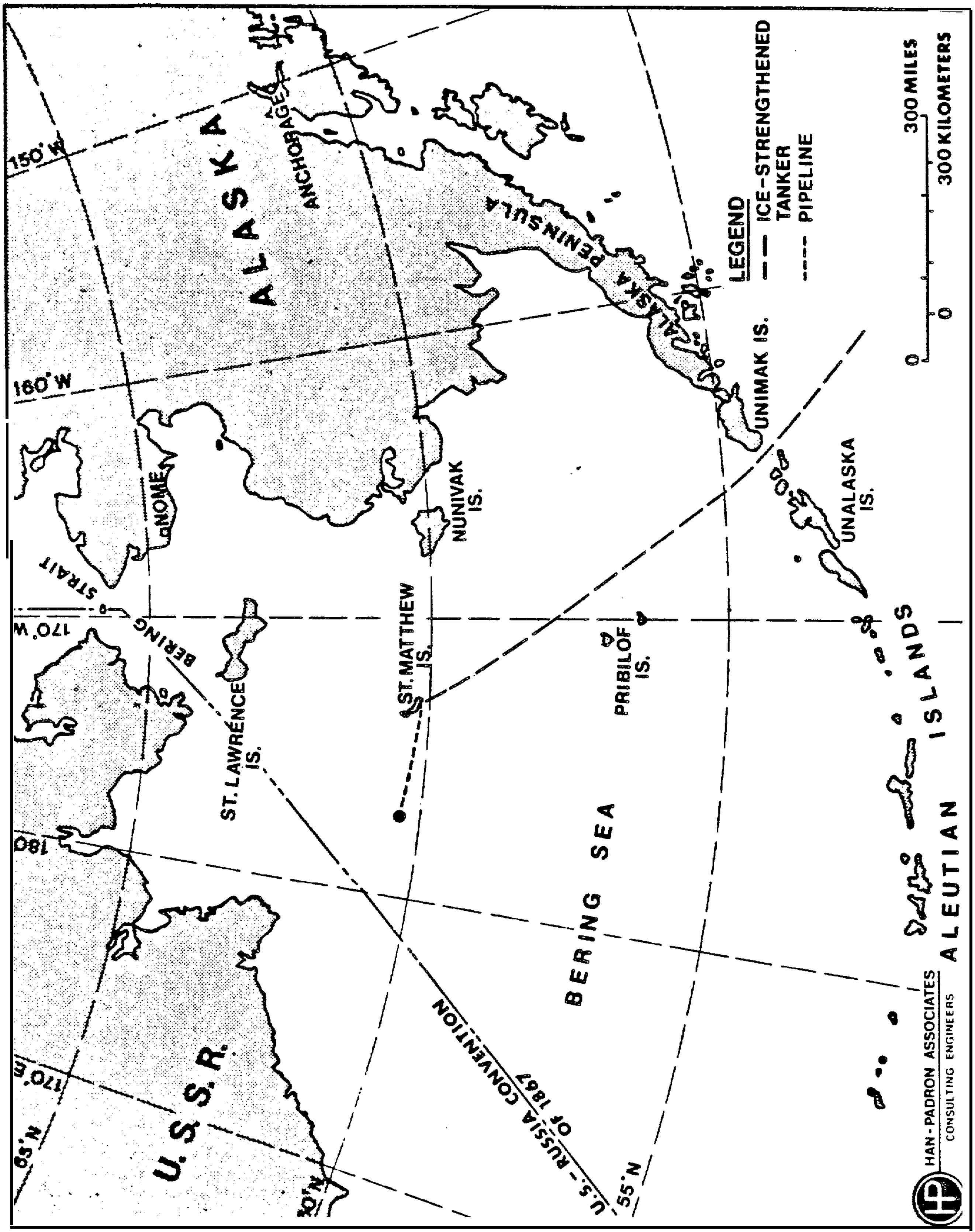

Figure 5-3. Scenario 2, Transportation Alternative B.

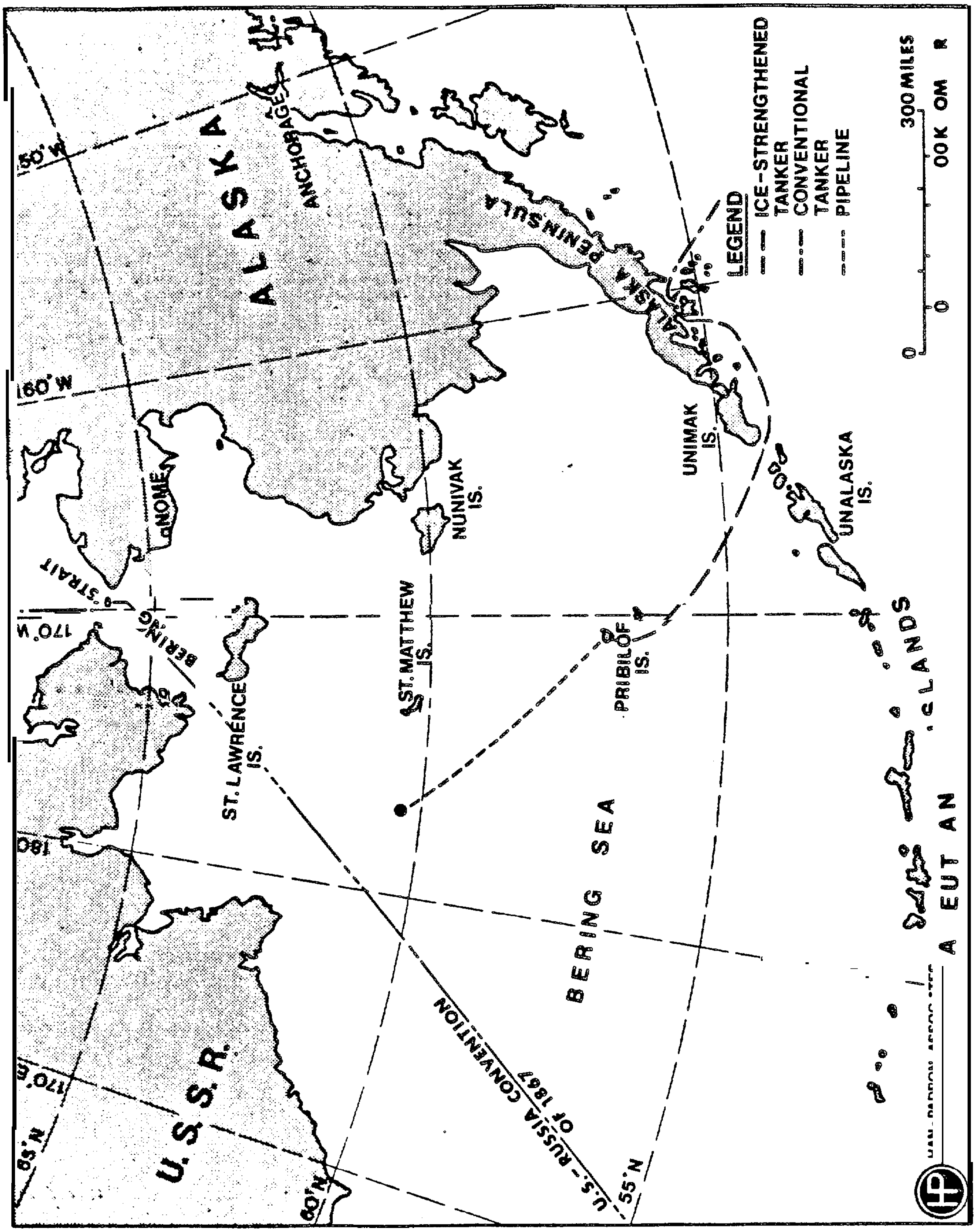

Figure 5-4. Scenario 2, Transportation Alternative C.

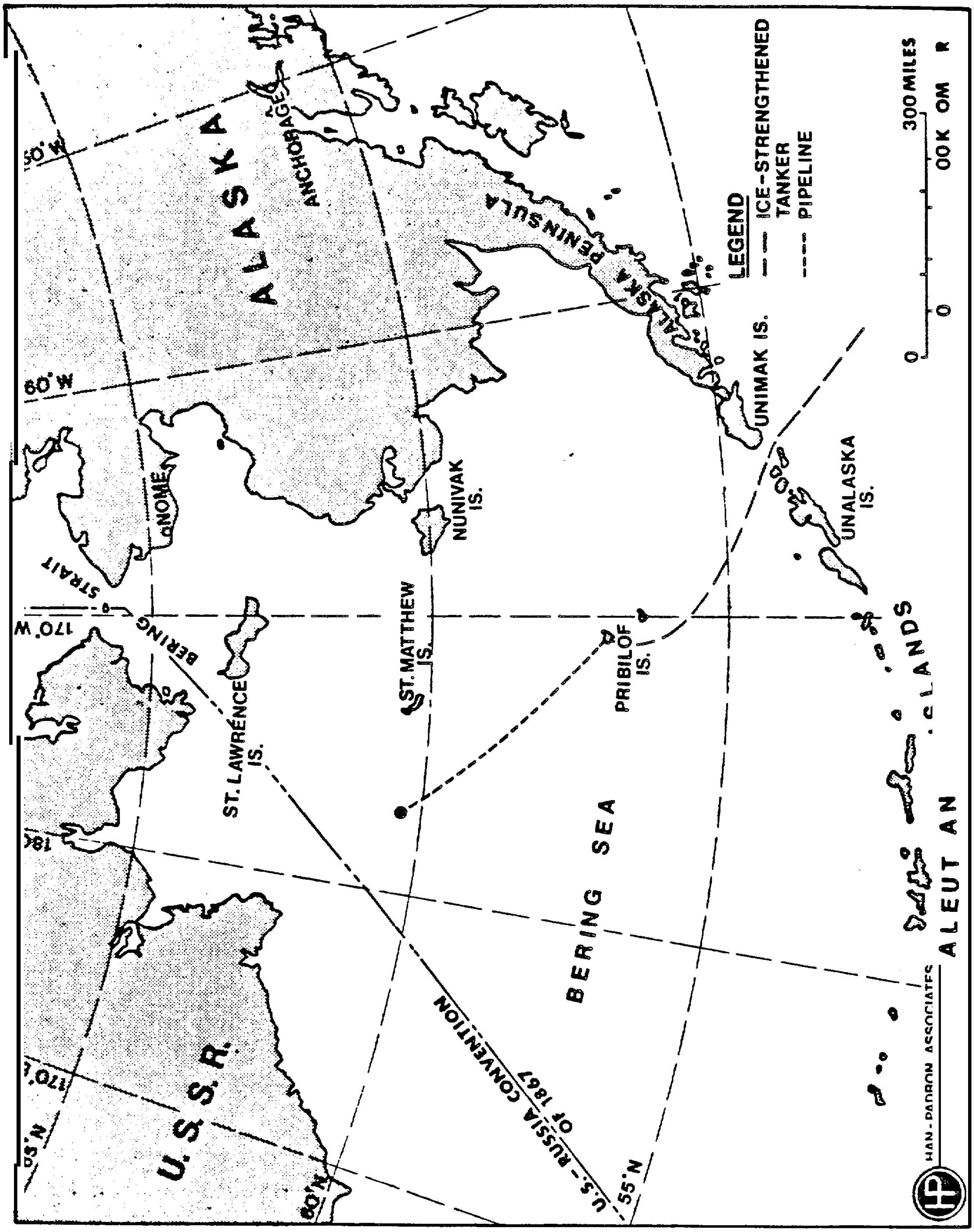

Figure 5-5. Scenario 2, Transportation Alternative D.

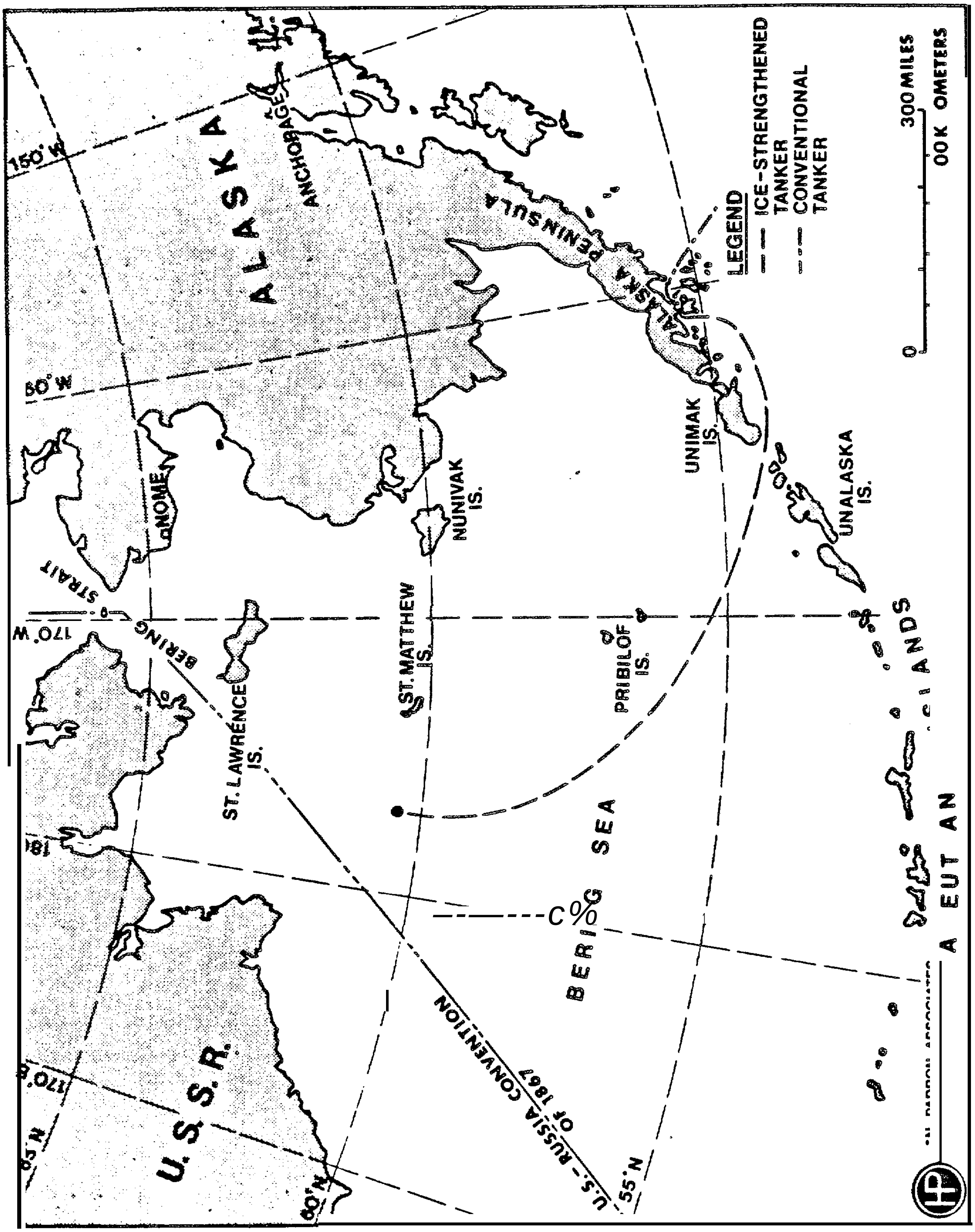

Figure 5-6. Scenario 2, Transportation Alternative E.

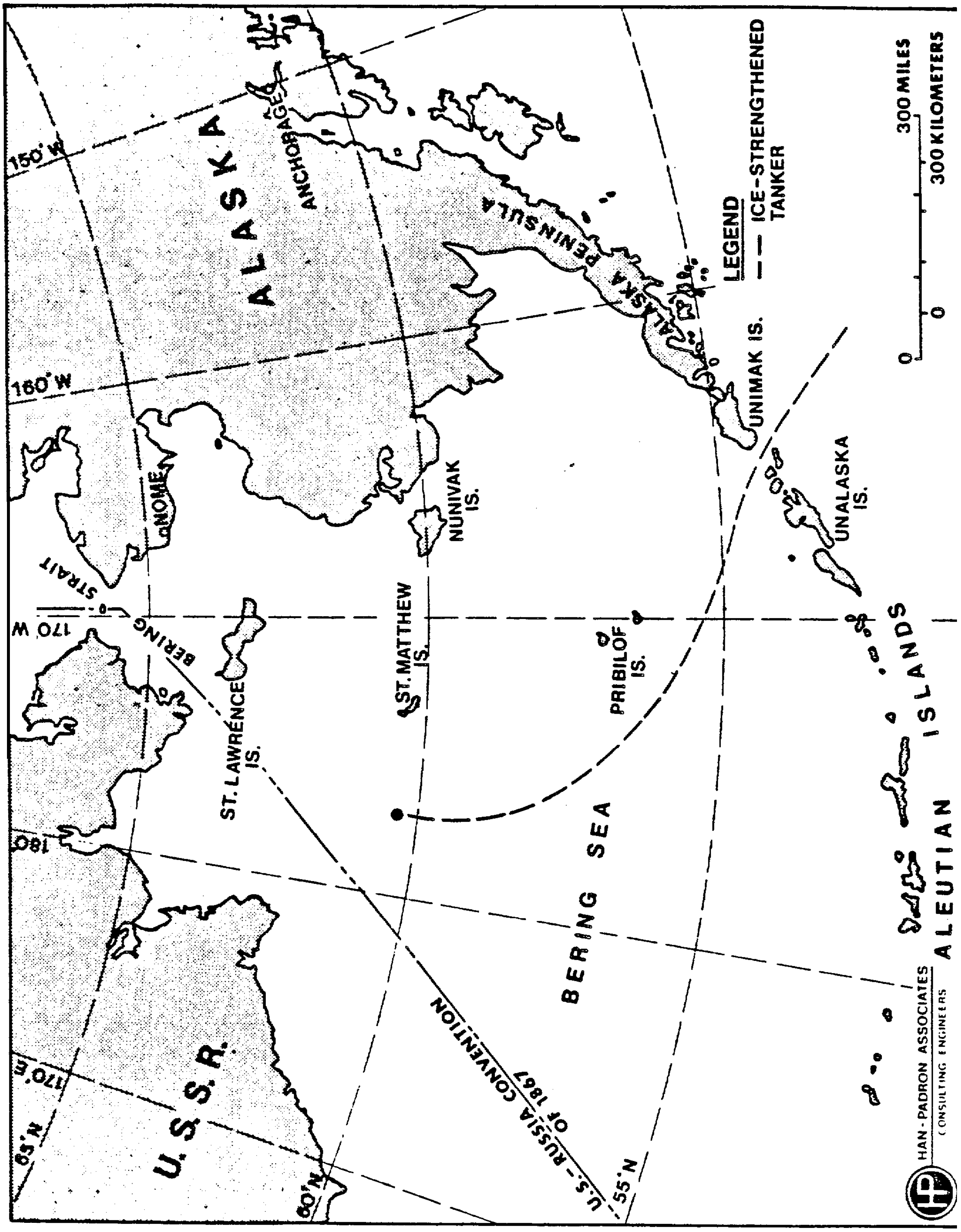

Figure 5-7. Scenario 2, Transportation Alternative F.

5.3 CRUDE OIL DESTINATIONS

For each of the transportation alternatives listed in Section 5.2, base case pipeline lengths and tanker route lengths that have been used in the evaluation of the alternative are listed below. When minimum and maximum lengths have been used for sensitivity analyses they are also listed. Where any likely variation in a pipeline or tanker route length was less than ten percent of the base case length, no length sensitivity analysis was performed.

	LENGTH km (mi)		
	Base Case	Min. Case	Max. Case
Alternative 2A			
Marine pipeline	240 (149)	180 (112)	300 (186)
Ice-strengthened tanker route	1160 (720)		
Alternative 2$			
Marine pipeline	240 (149)	180 (112)	300 (186)
Ice-strengthened tanker route	4110 (2555)		
Alternative 2C			
Marine pipeline	500 (310)	420 (260)	580 (360)
Ice-strengthened tanker route	780 (485)		
Conventional tanker route	3200 (1990)		

Alternative 2D			
Marine pipeline	500 (310)	420 (260)	580 (360)
Ice-strengthened tanker route	3730 (2320)		
Alternative 2E			
Ice-strengthened tanker route	1300 (810)		
Conventional tanker route	3200 (1990)		
Alternative 2F			
Ice-strengthened tanker route	4250 (2640)		

5.4 OFFSHORE LOADING TERMINAL

The offshore loading terminal for Scenario 2 consists of a catenary chain stabilized articulated column type structure with a permanently moored floating crude oil storage vessel and a pipeline connecting the production platform to the storage/loading system. For alternatives that require two berths, a catenary chain stabilized articulated column type mooring and a pipeline connecting the mooring to the storage/loading system are provided. The elements of the offshore terminal are shown schematically in Figure 5-8.

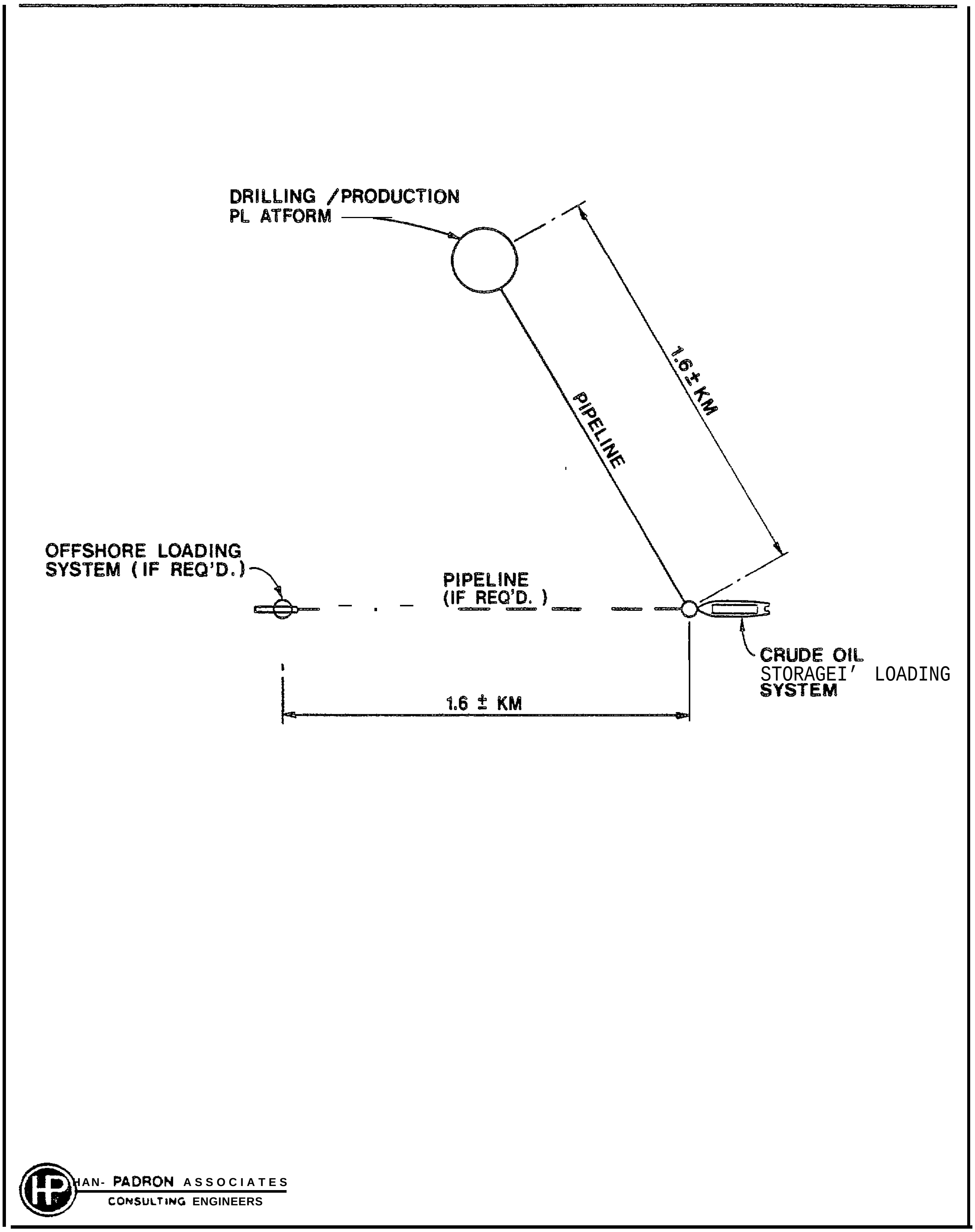

Figure 5-8. Scenario 2 schematic **layout** of offshore loading terminal.

For Scenario 2 the crude oil storage and tanker loading functions are combined in a single facility featuring a permanently moored floating storage vessel to which tankers moor in tandem for loading. For sensitivity analysis cases with very high production rates, two tanker loading facilities are required. In this case, the second loading system has no integral storage capacity but is connected to the storage vessel by means of a marine pipeline. As for the other scenarios, the crude oil storage facility is assumed to be separate from the drilling/production structure(s). However, if a large, gravity stabilized structure is used as the drilling/production platform, crude oil storage capability could be incorporated in the platform at a significantly lower cost per barrel than for the floating storage, thus making transportation alternatives that utilize offshore crude oil storage more economically attractive than indicated in the following analyses.

Descriptions of the offshore storage/loading system and the offshore loading system are given below. The design philosophy for loading system aspects is given in Section 3.5.1 and for crude oil storage volume requirements in Section 3.5.4. Details regarding the pipelines are provided in Section 3.5.5.

5.4.1 Offshore Storage/Loading System

The optimum offshore storage/loading system for the Central Bering Sea study area consists of a SPM tanker mooring with a permanently moored crude oil storage vessel, The deep water depths and relatively severe ice conditions require a unique offshore mooring concept capable of providing dependable year-round operation. After full evaluation of the alternative storage/loading system concepts feasible for operation in the central portion of the Bering Sea, based on the performance factors listeal in Section 3.5.1, a concept was selected to provide the requisite mooring, storage and loading facilities as shown in Figure 5-9. The system consists of a catenary chain stabilized articulated tower fixed to the seabed by a piled base with crude oil storage capacity provided by a floating storage vessel permanently yoke-moored to the tower. All power and manning requirements for operation of the terminal are located on the storage vessel. Since storage capacity requirements vary for the different alternatives considered, preliminary designs of the storage/loading system were prepared for a range of 0.5 million to 3.0 million barrels. It was found that, aside from the cost of the storage vessel, the variation in storage capacity had only minor effects on the design and cost. of the system.

The catenary stabilized tower concept was selected because it most efficiently resists the environmental ice loading while utilizing proven technology in structural and mechanical component design, and also provides established procedural guidelines for mooring and loading operations based on previous North Sea experience. Alternative concepts evaluated included:

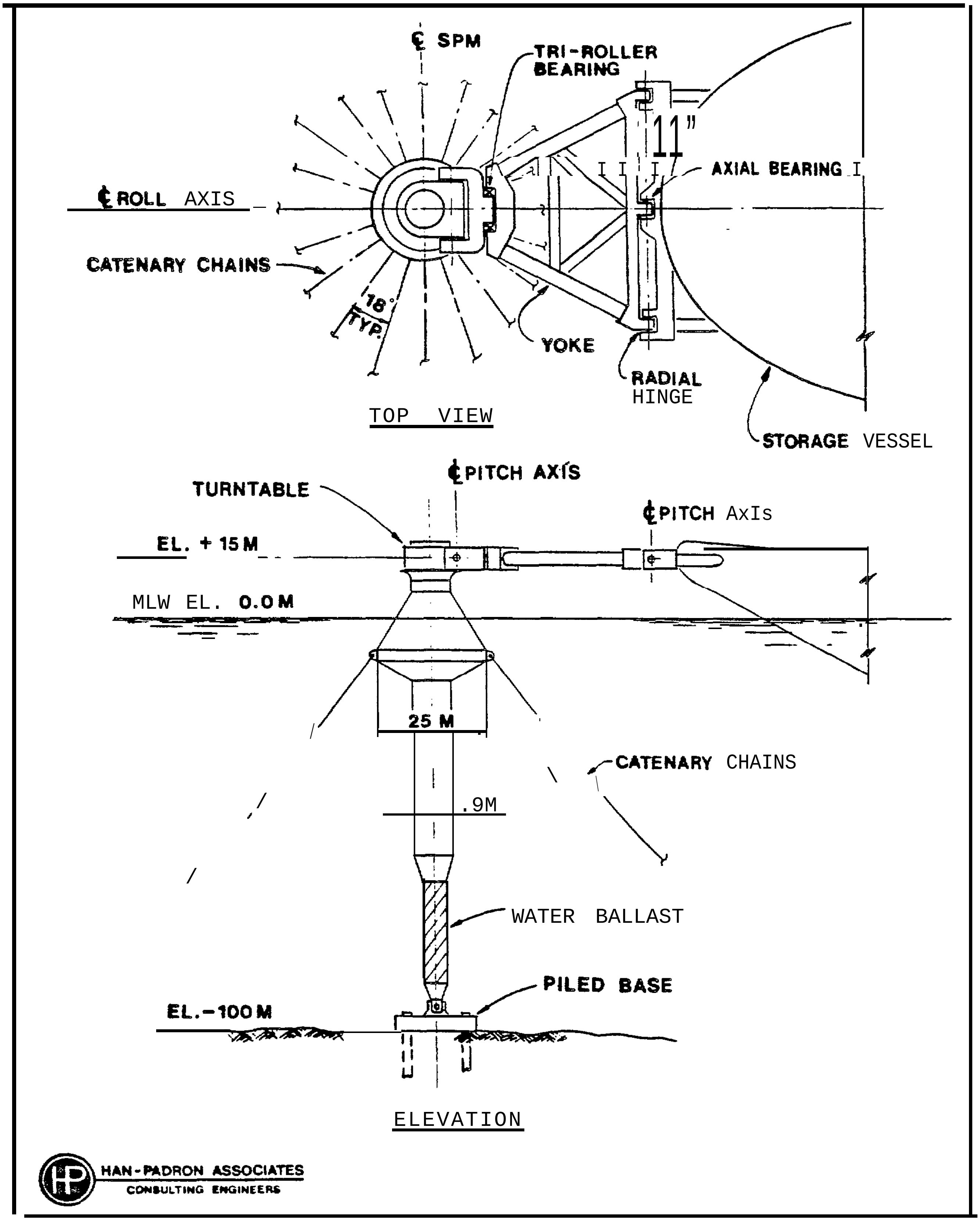

Figure 5-9. Scenario 2 offshore storage/loading system.

- catenary chain stabilized articulated tower with submerged loading/mooring system,
- catenary chain moored tanker turret system,
- buoyant articulated tower,
- buoyant articulated tower with submerged loading/mooring system,
- multiple articulated single anchor leg mooring system,
- catenary chain moored spar buoy,
- all of the above with bottom founded submerged storage in place of a floating storage vessel, and
- fixed, rigid gravity structure with integral storage.

Systems utilizing submerged, bottom founded storage appear to be approximately equal in cost to the floating storage vessel concept for the smaller storage capacities, but increase more rapidly with increasing capacity. In addition to cost, the floating storage was deemed preferable because:

- the segregated ballast system on the floating storage unit eliminates the need to discharge treated ballast water into the sea (A submerged storage system, in order to be of reasonable cost, must utilize a seawater/crude oil displacement system and the ballast water will require treatment before discharge.),
- maintenance and operating procedures on a tanker-like vessel are well established and proven while this is not true for a submerged storage system, and

- bottom founded storage structure feasibility is highly dependent on site-specific soil conditions, whereas floating storage is not.

Ice and wave loading govern the design of the storage/loading system. The environmental design criteria is given in Section 5.1 and the procedures for establishing the design forces are presented in Section 3.2. Ice forces acting on the loading terminal consist of icebreaking and clearing components on the SPM tower and on the permanently moored storage vessel. Taking due consideration of the fact that peak loads from sheet ice and pressure ridge failure and clearing mechanisms are not simultaneous, the governing total ice load on the tower and storage vessel was calculated to be 4700 t (10,400,000 lb). This load occurs when the sheet ice is breaking and clearing around the conically-shaped articulated tower and the design pressure ridge is being cleared around the storage vessel (sized for 3.0 million barrels storage capacity). By comparison, the ice load on the 0.5 million barrel storage system was calculated to be 4300 t (9,500,000 lb). The ice loading governs the restoring characteristics provided in the tower (amount of buoyancy and size and number of chains), the size and cost of the mechanical hinge and bearing systems, and the local design of the tower cone and ice-strengthened band on the storage tanker. The dynamic wave loading on the system governs the design of the tower structure and the foundation system. The maximum horizontal wave force on the system slightly exceeds 3200 t (7,100,000 lb), with 1100 t (2,400,000 lb) of the total applied to the base foundation. The remaining load is partially resisted by the elasticity of the deflected mooring and by the damping characteristics of the moored storage vessel. The dynamic wave loading also causes the maximum vertical forces throughout the tower and especially affects the design of the base articulation and foundation piling. The large volume ice breaking cone significantly contributes to the total vertical wave load fluctuation of 3200 t (7,000,000 lb) applied to the foundation.

An important consideration in the design of the storage/loading system is the effect of a change in direction of the ice motion while the storage vessel is in the middle of a large ice floe. If the change in direction is gradual and continuous, the vessel will simply west.herwane~ causing no problems. On the other hand, if the ice floe comes to a stop and subsequently resumes movement in a direction close to 90 degrees away from its initial movement, extremely high forces could be developed in the system. However, preliminary analysis indicates that the storage vessel can be designed so that the maximum force in the tower developed under these circumstances is less than the 4700 t (10,400,000 lb) maximum force indicated above. This can be accomplished by providing the storage vessel with a bulbous shaped bow outline in plain view so that the ice force acts only around the forward end of the vessel, permitting it to change heading into the direction of ice movement, This vessel is also provided with a steep side rake near the bow to reduce ice breaking forces. Such a vessel configuration, combined with the fact that the design ice feature assumed to change direction 90 degrees after coming to a stop, will be significantly smaller than the 100 year ice event, will result in tower and foundation forces that do not control their design. However, this loading condition may control the design of some of the system elements such as, the axial bearing, yoke, tri-roller bearing and main turntable bearing.

Although the addition of the conical skirt to the otherwise slender articulated tower significantly increases the wave forces on the system, its beneficial ice breaking effects are exceptional. The vertical surface of a 9 m (30 ft) diameter cylinder requires approximately ten times the force to fail the design pressure ridge as does the conical surface. Without the cone, it becomes evident that the selected concept would not be suitable to resist the increased loading. Hence, the addition of the cone represents the difference between a feasible and an unworkable solution.

The single piece tower assembly extends 15 m (50 ft) above still water level to the yoke frame centerline. The icebreaker cone extends from 6 m (20 ft) above the waterline to 7.6 m (25 ft) below. The twenty 15 cm (6 in.) diameter catenary chains are attached to the perimeter of the cone's base and drape to the seafloor in a pre-determined, pretensioned, catenary profile. The chains are anchored to the seabed by single large diameter piles. The configuration selected does not require clump weights or mats since adequate restoring force is supplied by the weight of the chains. The remainder of the tower consists of a 9 m (30 ft) diameter shaft reducing to 6 m (20 ft) diameter for the lower 30 m (100 ft). The final 6 m (20 ft) of the shaft reduces to mate with the hi-axial universal joint secured to the base structure.

The tower is divided into eight watertight compartments by horizontal bulkheads. The number and spacing of the compartments assures that the tower remains stable and operational during an accidental situation of two adjacent compartments flooding. In addition, all exterior compartments adjacent to the conical shell may be flooded as a result of plate puncture or rupture without affecting tower operation. Local design of the icebreaker cone provides for ice pressures over small areas up to 6.2 mPa (900 psi). The cylindrical shaft is stiffened by circumferential ring stiffeners to resist axial compression and hydrostatic collapse interaction failure. All stresses throughout the structure are kept below the fatigue governing values,

The turntable is fixed to the 9 m (30 ft) diameter tower shaft by two sets of large diameter roller bearings. The turntable is protected from ice ride-up impacts by a deflector shield fitted over the main shaft. The extremely large ice forces transferred to the tower from the moored storage vessel, approximately 4000 t (8,800,000 lb), necessitate a system of bearings and hinges far different than on any existing installation. The turntable provides vertical and radial support for the yoke tip while permitting the vessel to weathervane about the mooring structure in compliance with prevailing environmental conditions. Two sets of radial hinges, one at the turntable end and one the vessel end of the yoke, permit the vessel to heave and pitch without applying forces to the tower. A tri-roller, large diameter bearing connects the separate yoke tip to the triangular shaped yoke frame, thus permitting roll motion of the vessel while transferring all radial and tangential loads to the tower. An axial bearing at the vessel end of the yoke isolates tangential loads from the two adjacent radial hinges.

The storage vessel is similar in design to icebreaker tankers except for the minimal power requirements. It has segregated ballast compartments to limit the draft range and reduce the width of its ice strengthened band. The storage vessel has a bow profile design more suitable for ice breaking than the ice-strengthened tankers. Whereas the tanker bow profile is a compromise between ice breaking and open water navigational requirements, the storage vessel needs only to break ice, and to do so more efficiently due to the lack of power and forward momentum used most advantageously by the tankers. The bow of the storage vessel, therefore, requires a steep forward rake angle of 30 degrees at the waterline and preferably a bulbous shaped bow outline in plan view to provide a steeper than normal side rake angle and to aid in sheet ice clearing along the remaining length of the vessel. The steeper side rake will aid the vessel in breaking ice floes approaching from off-bow headings as descirbed above. While such a configuration will probably result in poorer vessel performance compared to a conventional tanker configuration in open water storm conditions, the maximum forces acting on the system under these conditions will be less than the maximum ice induced forces. Model testing will be required to determine the optimum configuration.

The stern of the storage vessel requires mooring line attachment fittings and a loading hose gantry structure for the tandem mooring of ice-strengthened tankers. Figure 5-10 shows the tandem mooring arrangement. Since the bow of the storage vessel is considerably wider than the tanker, it will provide a relatively ice-free approach lead for the tanker during most conditions of heavy ice coverage and keep ice forces transferred through the mooring lines to readily manageable levels.

Capital costs for the storage/loading system versus water depth are shown in Figure 5-11 for the case of 1.0 MMB storage capacity. The increase in capital cost with water depth is primarily the result of the increased cost of the stabilizing catenary chains and the lengthened tower. The floating storage vessel, accounting for approximately 60 percent of the 1.0 MMB storage/loading system cost, is unaffected by varying water depth. Ice forces on the system are also unaffected by increasing water depth. However, the restoring force characteristics of the tower are favorably influenced by the deeper water and thus result in greater overall efficiency.

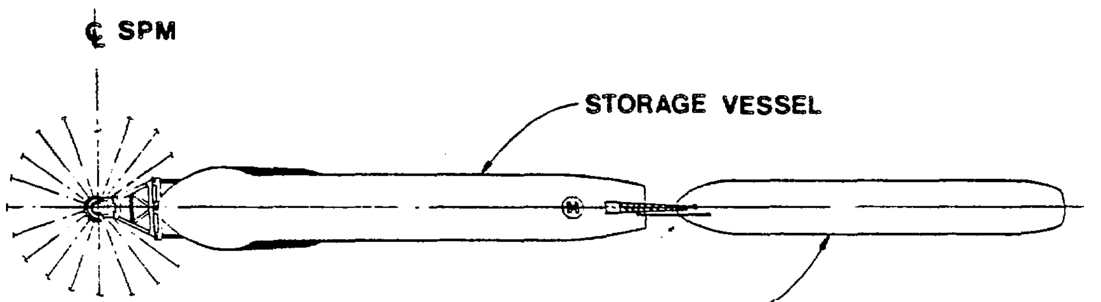

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Figure 5-10. Scenario 2 offshore storage/loading system tandem mooring configuration.

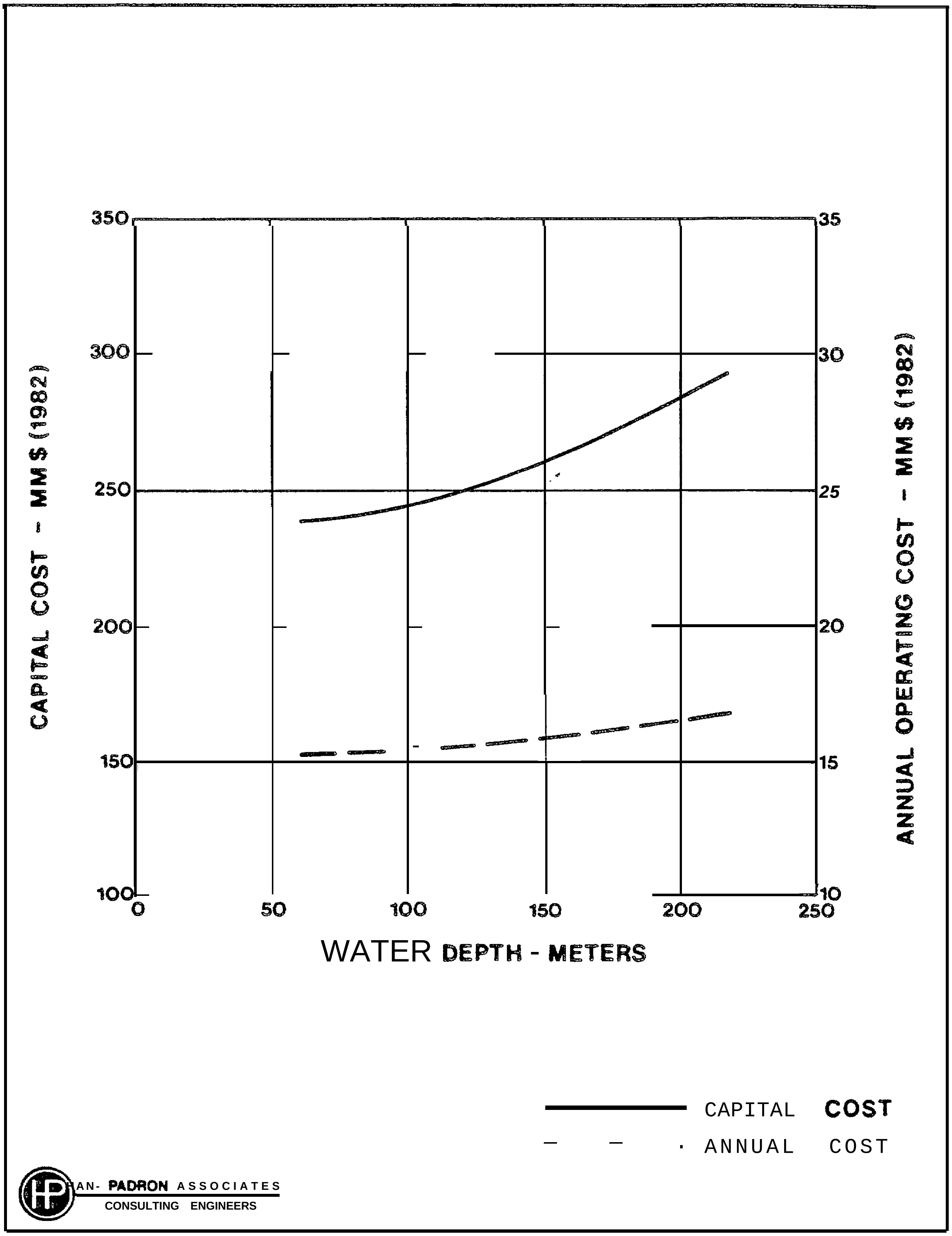

Figure 5-11. Scenario 2 offshore storage/loading system **capital** and **annual costs versus** water **depth.**

The base case soil condition for the Central Bering Sea study area, as discussed in Section 5.1, is composed of silty cohesive soil and has been used as the basis for the preliminary design of the foundation systems. The alternative case soil consists of cohesionless material that provides superior foundation characteristics compared to those of the base case. However, the foundation cost of the selected storage/loading system is relatively small in comparison to the cost of the other components and the superior soil results in less than a 0.5 percent savings on the total capital cost of the system.

Capital cost versus storage capacity is illustrated in Figure 5-12 for the storage/loading system at the base case water depth, The variation in capital cost is almost totally attributable to the variation in cost of the floating storage vessel. The increase in vessel size with storage capacity results in slightly higher ice loading on the system but has very little influence on the cost of the tower structure. Of the total cost increase resulting from increased storage capacity, 3.5 percent is due to increase in the tower structure cost and the remainder due to increase in the storage vessel cost.

Annual operating and maintenance cost for the offshore storage/loading system has been established on the basis of the operating "manpower cost plus 3.0 percent of the capital cost. The annual cost is shown in Figure 5-11 versus water depth and Figure

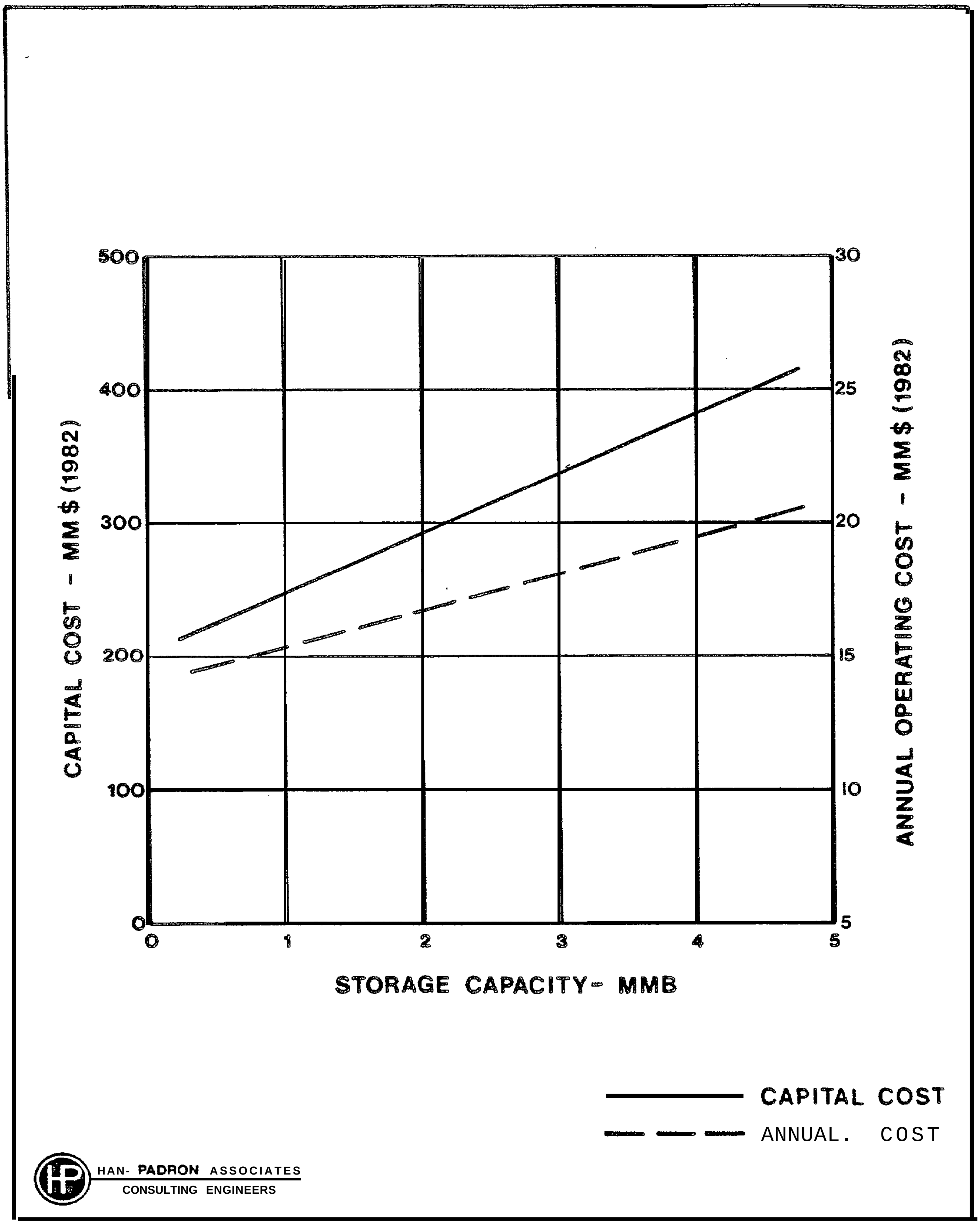

Figure 5-12. **Scenario** 2 offshore **storage/loading** system capital **and annual costs versus** storage capacity.

5-12 versus storage capacity.

The manpower required to operate and maintain the offshore storage/loading system is estimated to be 40 men times a rotation factor of two.

The berth availability rate, as defined in Section 3.5.2, has been established for the Scenario 2 offshore storage/loading system based on the criteria listed in Section 3.5.2, and summarized as follows:

- Ice and visibility conditions will not limit mooring operations.
- Mooring operations will take place in seas with a significant wave height of 3.0 m (10 ft).
- Unscheduled maintenance causes 5 percent maintenance downtime.

The average frequency of occurrence, over the worst three consecutive months, of significant wave heights exceeding 3.0 m (10 ft), based on wave height threshold data contained in "Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska" (Brewer et al. 1977), is approximately 35 percent. Allowing for 5 percent unplanned maintenance downtime, the berth availability rate of the offshore storage/loading system for this scenario is 60 percent.

5.4.2 Offshore Loading System

For the base case production rate, only one ice-strengthened tanker loading berth is required and it' consists of the storage/ loading system described above. However, for the high production rates considered in some of the sensitivity analyses, a second tanker loading berth is required. The second berth is quite different from the first in that it contains no crude oil storage capacity. A pipeline connects the second tanker berth to the adjacent storage/ loading system, as illustrated schematically in Figure 5-8.

'The concept development and selection for the optimum offshore loading system without storage capacity followed the same evaluation procedure as for the storage/loading system. The selected offshore loading system without storage capacity for the Central Bering Sea study area is shown in Figure 5-13. The system consists of a catenary chain stabilized articulated tower fixed to the seabed by a piled base. The catenary chains, assisted by buoyancy in the tower, provide the restoring force characteristics required to resist the environmental loads resulting from wind, wave, ice and current acting on the tower and moored tanker. Power and manning requirements for operation of the loading berth are located on the tower turntable above the wave zone. Preliminary designs on which the cost analyses are based have been prepared for various water depths and seabed geotechnical conditions. The variation in ice-strengthened tanker " size for the several transportation alternatives requiring a second

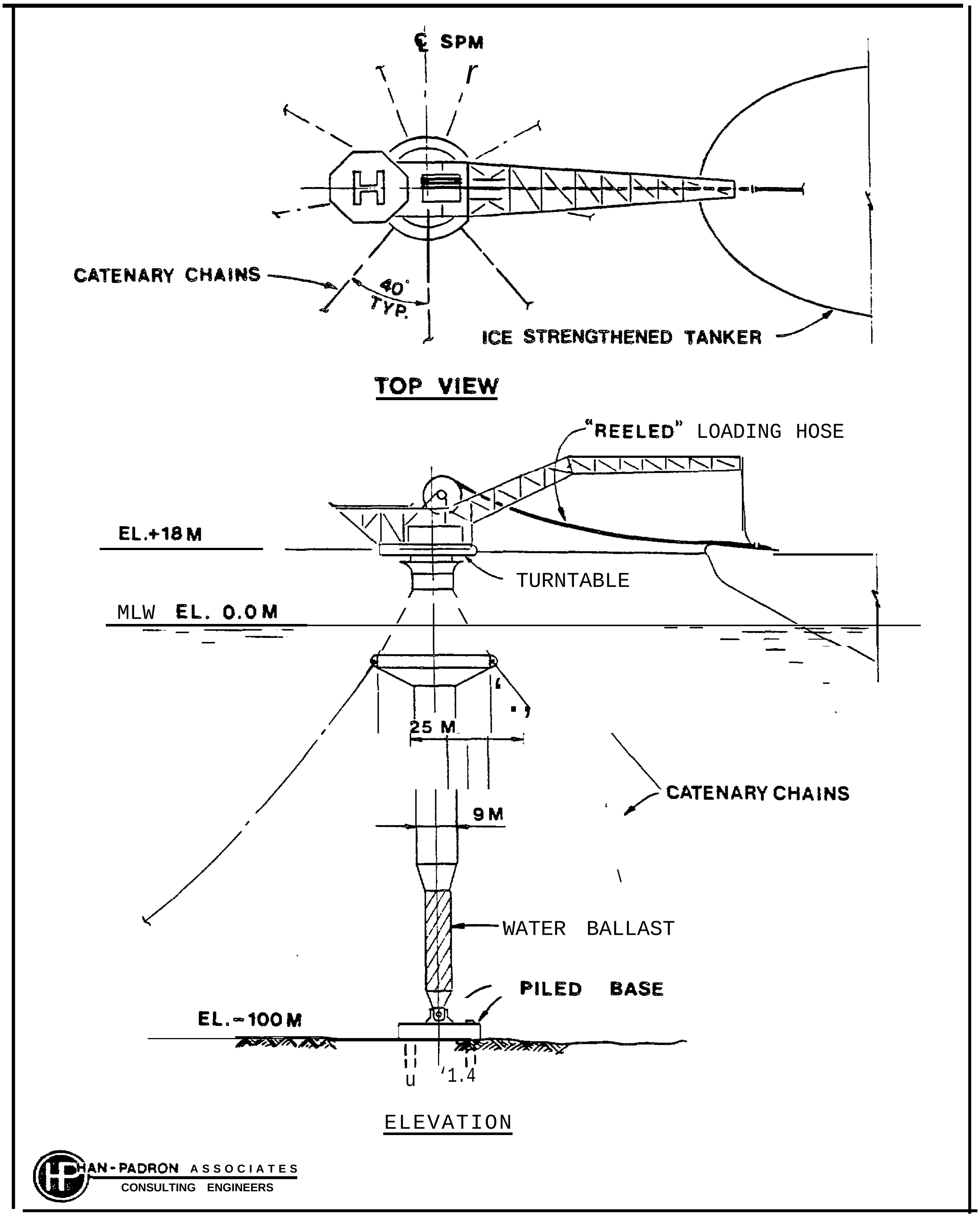

Figure 5-13. Scenario 2 offshore loading system.

loading berth is less than 10 percent and has no effect on the cost of the system. Therefore, a tanker size of 200,000 DWT was utilized for the preliminary designs and a tanker size sensitivity analysis omitted.

Ice and wave loading govern the design of the offshore loading system. Section 5.1 contains the environmental design criteria utilized and Section 3.2 outlines the procedures followed in establishing the environmental design forces on the system. Ice forces consist of breaking and clearing components on both the tower and ice-strengthened tanker. The tower, without a moored tanker, is designed for the 100 year maximum ice feature or wave condition. During periods of tanker mooring and loading operations, the criteria for design ice features is reduced from a 100 year recurrence interval to a 1 year recurrence interval. The design wave height is also reduced to the maximum established for safe loading operations. If ice or wave conditions exceed these limits, the tanker will cast-Off* After evaluation of all appropriate combinations of simultaneous peak ice loads on the tower and tanker, the governing total ice force on the offshore loading system was calculated to be approximately 2000 t (4,400,000 lb). This loading occurs for the combination of the 1 year sheet ice thickness breaking and clearing on the conical skirted tower and the 1 year ice ridge clearing the moored tanker.

The ice force acting on the tanker accounts for approximately

75 percent of the governing total ice force. The mooring hawsers will thus be required to transfer a 1500 t (3,300,000 lb) force to the tower. This force is considerably higher than the maximum mooring hawser forces at existing offshore loading systems. Therefore, special attention to the selection, design and detailing of the mooring hawser system will be required. If, for example, two grommet type hawsers are used, each must have a breaking strength of approximately 1500 t (3,300,000 lb), requiring the use of 140 mm (5.5 in.) diameter wire rope or 150 mm (6 in.) diameter kevlar rope. These sizes are larger than are normally available. Care must also be exercised in the arrangement of the hawsers and detailing of the hawser connections to ensure that the load is reasonably equally distributed between the two lines. During open water season, the special ice season mooring hawser system could be replaced with a more conventional nylon hawser system.

The ice forces govern the design of the restoring components of the tower (buoyant volume and size and number of chains), the local design of the cone, the turntable bearing systems and the mooring hawsers. The dynamic wave load condition, without the tanker moored to the tower, governs the design of the tower shaft and foundation. The maximum total horizontal wave force on the structure is approximately 2500 t (5,500,000 lb). This is less than the force on the storage/loading system due to the increased tower compliancy that results from the absence of the damping influence of the permanently moored storage vessel. However, a greater portion of the horizontal force, 1500 t (3,300,000 lb), is applied to the foundation of the offshore loading system. Vertical wave forces are comparable to those acting on the storage/loading system.

As previously discussed, the addition of the icebreaking cone is required to reduce the peak ice forces acting on the system. Nine 15 cm (6 in.) diameter chains are attached to the perimeter of the cone and drape in a pretensioned, catenary profile to the seabed. Attachment of each chain to the seabed is accomplished by a single large diameter pipe pile. The main tower shaft extends from the turntable at the top, through the cone attachment, and connects to the hi-axial universal joint secured to the base structure. Details of the main tower are similar to those of the storage/loading system tower described in Section 5.4.1.

The turntable is attached to the tower shaft by a large diameter slew bearing arrangement that permits the moored tanker to weathervane about the mooring in compliance with the prevailing environmental conditions. Living quarters and power generation equipment are located on the turntable deck and within the main tower shaft. A heliport is fixed on top of the turntable boom which supports the loading hoses and messenger lines.

The capital cost for the offshore loading system in the central study area is given in Figure 5-14 versus water depth. The increase in capital cost with water depth is attributable to the

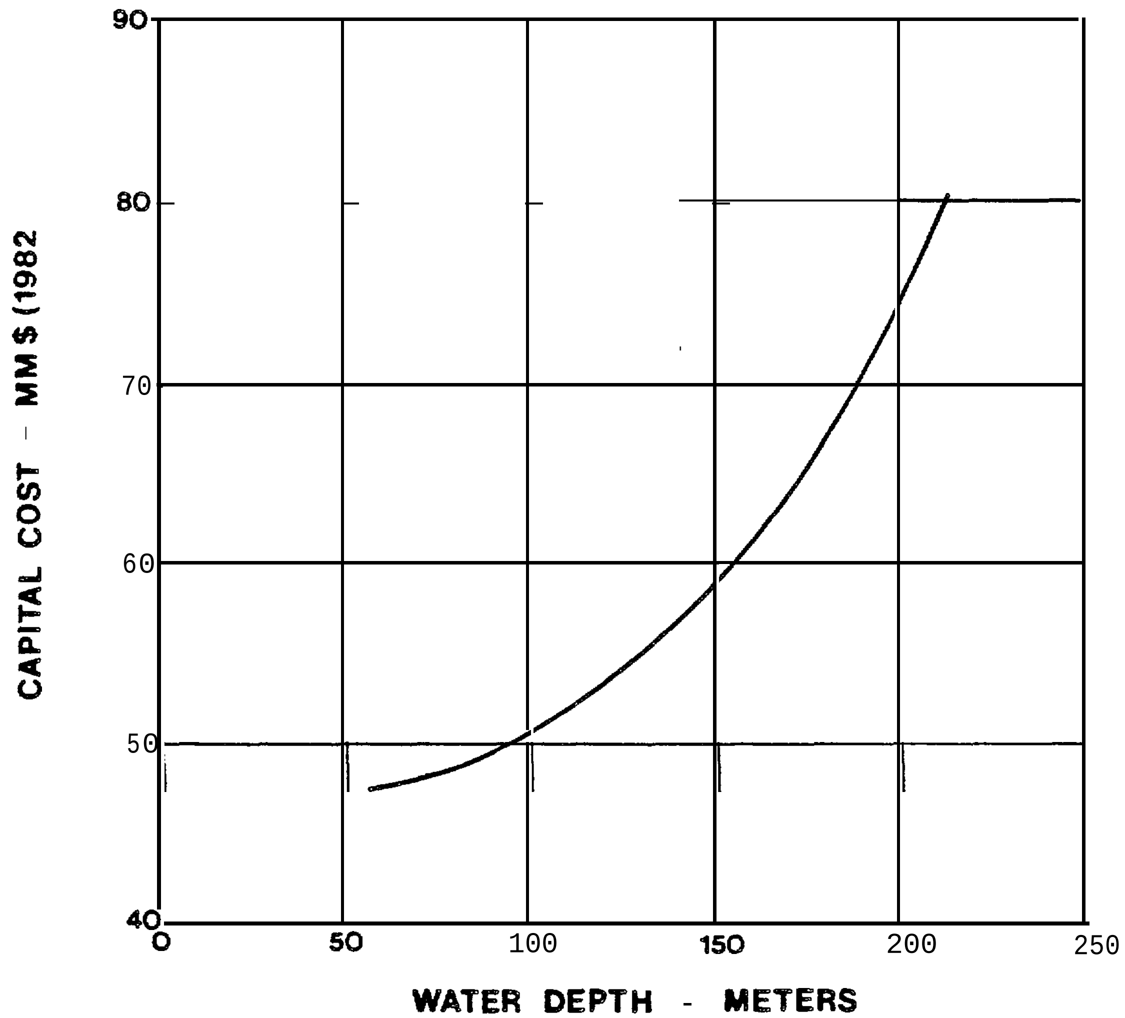

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Figure 5-14. Scenario 2 offshore loading system capital cost versus water depth.

increased tower length and the substantial lengthening of the catenary anchor chains.

As discussed for the storage/loading system, the alternate sensitivity case soil results in a more favorable foundation condition and reduces the total capital cost of the system by approximately 0.5 percent from the base case capital cost.

Annual operating and maintenance cost for the offshore loading system is estimated to be approximately $4.0 million. The manpower required to operate and maintain the system is estimated to be 10 men times a rotation factor of two.

The berth availability rate for the offshore loading system is based on the same criteria as described above for the offshore storage/loading system except that the significant wave height in which mooring operations can take place is increased to 4.0 m (13 ft). The average frequency of occurrence of waves with a significant height greater than 4.0 m (13 ft) in the worst three consecutive months is approximately 23 percent. Allowing for 5 percent unplanned maintenance downtime, the berth availability rate is 72 percent.

5.5 NEARSHORE LOADING TERMINAL

The nearshore loading terminals for the Scenario 2 transportation alternatives are located either on St. Matthew or St. Paul Island where the ice conditions are less severe than for the Scenario 1 nearshore loading terminal. However, except for the loading pipeline as discussed in Section 3.5.5, the nearshore terminals for Scenario 2 are essentially the same as for Scenario 1. Even the tanker loading system will be essentially the same because although the ice forces acting on it are lower, the wave forces are slightly higher so that the peak loading on the nearshore loading system is almost the same for the two scenarios.

For further discussion of the nearshore loading terminal, refer to Section 4.5.

5.6 OPTIMIZATION OF TRANSPORTATION ALTERNATIVES

The optimum size/number/capacity of each of the transportation system elements of each of the six Scenario 2 alternatives, based on the base case scenario parameters, are listed in Table 5-1. The optimum size and number of ice-strengthened and conventional tankers have been developed as described in Section 3.4.1. The ice class of escort icebreakers has been developed as described in Section 3.4.4. The berth occupancy rates and number of berths for each type of terminal have been developed as described in Section 3.5.3. The optimum storage capacity for each type of terminal has been developed as described in Section 3.5.4. The loading pipeline diameter has

TABLE 5-1

SCENARIO 2 OPTIMUM TRANSPORTATION SYSTEM ELEMENTS

TRANSPORTATION ELEMENT	ALTERNATIVE 2A	2B	2C	2D	2E	2F
Ice-strengthened Tankers						
Ice Class	2	2	1	1	2	2
Size (MDWT)	62	157	48	145	75	160
Number	2	2	2	2	2	2
Icebreakers						
Ice Class	3	3	2	2	3	3
Number	2	2	2	2	2	2
Conventional Tankers						
Size (MDWT)	127	-	127		127	
Number	2		2		2	
Offshore Loading Terminal						
Berth Occupancy Rate (%)					40	18
Number of Berths					1	1
Storage Capacity (MMB)					1.0	1.7
Loading Ppl Dia (in.)					26	26
Nearshore Loading Terminal						
Berth Occupancy Rate (%)	39	19	26	20		
Number of Berths	1	1	2	1		
Storage Capacity (MMB)	0.9	1.6	0.8	1.5		
Loading Ppl Dia (in.)	30	40	28	38		
Transshipment Terminal						
Berth Occupancy Rate (%)	26		32		24	
Number of Berths	2		2		2	
Storage Capacity (MMB)	1.6		1.6		1.6	
Load./Unload. Ppl Dia (in.)	36		36		36	
Marine Pipeline						
Diameter (in.)	20	20	24	24		
Length (km)	240	240	500	500		
Land Pipeline						
Diameter (in.)						
Length (km)						

been developed as described in Section 3.5.5. The marine pipeline diameter and length have been developed as described in Section 3.6 and the land pipeline diameter and length as described in Section 3,7.

5.7 COMPARISON OF TRANSPORTATION ALTERNATIVES

Each Scenario 2 crude oil transportation alternative has been compared on the basis of total cost over the life of the reservoir, based on a discount rate of 8 percent, as described in Section 5.7.1. The various alternatives have also been compared based on factors other than cost, such as, construction logistical and timing problems, environmental factors and reliability, as described in Section 5.7.2.

5.7.1 cost

The total cost of the crude oil transportation system over the life of the reservoir, which has been assumed to be 15 years, has been calculated for each alternative and the results are presented in Tables 5-2 through 5-7. The tables show the capital cost for each major transportation system element, the characteristics of which are listed in Table 5-1. For each element, the annual operating cost, during a peak production year, is also shown, as is the manpower required to operate the element. The manpower figures presented are

TABLE 5-2

TRANSPORTATION ALTERNATIVE 2A

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	292	30	Excl
ICEBREAKERS	127	17	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	..-	---	---
NEARSHORE LOADING TERMINAL	320	18	140
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	321	11	---
LAND PIPELINE	...	---	..-
TOTAL	1737	124	380

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2860

AVERAGE TRANSPORTATION COST PER BARREL = $ 6.66

TABLE 5-3

TRANSPORTATION ALTERNATIVE 2$

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	366	38	Excl
ICEBREAKERS	127	17	100
CONVENTIONAL TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL.	---	---	---
NEARSHORE LOADING TERMINAL.	396	19	120
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	321	10	...
LAND PIPELINE	---	---	---
TOTAL	1210	84	220

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 1980

AVERAGE TRANSPORTATION COST PER BARREL = $ 4.61

TABLE 5-4

TRANSPORTATION ALTERNATIVE 2C

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	264	28	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	---	---	---
NEARSHORE LOADING TERMINAL	437	22	140
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	796	28	...
LAND PIPELINE	-.-	---	---
TOTAL	2254	139	380

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 3510

AVERAGE TRANSPORTATION COST PER BARREL = $ 8.18

TABLE 5-5

TRANSPORTATION ALTERNATIVE 2D

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	340	34	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	---	...	Excl
OFFSHORE LOADING TERMINAL	---	---	---
NEARSHORE LOADING TERMINAL	386	19	120
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	796	28	---
LAND PIPELINE	---	---	---
TOTAL	1602	93	220

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2450

AVERAGE TRANSPORTATION COST PER BARREL = $ 5.71

TABLE 5-6

TRANSPORTATION ALTERNATIVE 2E

COSTS AND HANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-y r
ICE-STRENGTHENED TANKERS	302	32	Excl
ICEBREAKERS	127	17	100
CONVENTIONAL TANKERS	254	26	Exe-l
OFFSHORE LOADING TERMINAL	260	15	80
NEARSHORE LOADING TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	1366	113	320

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2380

AVERAGE TRANSPORTATION COST PER BARREL = $ 5.56

TABLE 5-7

TRANSPORTATION ALTERNATIVE 2F

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	368	40	Excl
ICEBREAKERS	127	17	100
CONVENTIONAL TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL	288	16	80
NEARSHORE LOADING TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	783	73	180

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 1440

AVERAGE TRANSPORTATION COST PER BARREL = $ 3.35

the crew size times a "shift factor" and times a "rotation factor." Tanker crews are not included.

The present value of the total life cycle cost is listed at the bottom of the tables. These figures are based on constant January 1982 dollars and an 8 percent discount rate. The effect of taxes or royalties is not included.

To obtain the average transportation cost (ATC) of the crude oil, on a per barrel basis, the present value of total cost is divided by the total volume of oil produced over the 15 year life of the reservoir.

Transportation alternative 2F results in the lowest ATC for Scenario 2.

5.7.2 Other Factors

There are a number of factors, other than costs, which may affect the selection of a crude oil transportation system for Scenario 2. These factors are difficult, if not impossible, to quantify and are described below.

a) Construction Time and Logistics

Construction time for each alternative is approximately four years. Therefore, there is no preference for a particular alternative on this basis.

For offshore terminal alternatives, most fabrication work is performed off-site and the minimal amount of on-site work required can be supported from the construction camp set up for drilling/production construction operations. Nearshore and transshipment terminal construction activities will probably require the establishment of a construction camp to support tank farm and long marine pipeline construction.

St. Matthew Island is currently a National Wildlife Refuge and as such is not open to private development. Obtaining the required change in the status of the island may be extremely time-consuming and result in a delay of the development program.

St. Paul Island is inhabited but does not have sufficient infrastructures to support construction operations of a significant magnitude.

b) Reliability

All alternatives considered for Scenario 2 require tankers to travel through the Bering Sea ice field. Alternatives 2A, 2B, 2E and 2F require approximately the same length of travel through ice while Alternatives 2C and 2D require considerably less. From this point of view, Alternatives 2C and 2D can be considered more reliable.

The risk of damage to a pipeline and consequent shutdown increases with its length. Considering only this factor, Alternatives 2E and 2F are the most preferable and Alternatives 2C and 2D are the least.

For Scenario 2, both offshore terminals and nearshore terminals require mooring and loading of tankers at a single point mooring in a location exposed to ice and waves. Ice conditions are somewhat less severe for Alternatives 2C and 2D but there is not a significant difference among the six alternatives.

Scenario 2 nearshore loading terminals do not require tankers to moor to a storage vessel. Therefore, alternatives that utilize a nearshore terminal instead of an offshore terminal will have a higher berth availability rate. However, this difference in berth availability has been taken into account in the determination of each element of the transportation system and all alternatives will have approximately the same reliability in this regard.

c) Environmental Considerations

From the point of view of minimizing disturbance of the environment, offshore storage is preferable to onshore storage. Onshore storage requires development of a large land area and the construction of a pipeline in a trench through the nearshore arid surf zone. Operating personnel for offshore storage are quite isolated from existing communities. Onshore storage requires a large amount of on-site construction personnel and equipment while most construction activities for offshore storage take place off-site. Considering these factors, Alternatives 2E and 2F are preferable to the other four alternatives.

The greater number of times the crude oil is loaded and unloaded en route to the refinery, the greater is the risk of a spill and subsequent damage t-o the environment. Therefore, alternatives that do not require a transshipment terminal (2B, 2D and 2F) are preferable to those that do (2A, 2C and 2E).

d) Other Considerations

In accordance with the terms of reference for this study, the alternatives that provide for offshore storage have been based on the assumption that the crude oil storage facility will be separate from the drilling/production structure(s). However, the drilling/production platforms for Scenario 2 are likely to be large gravity type concrete structures, similar to the North Sea Condeep structures, in which ample space for crude oil storage can be provided at relatively little additional cost. If this were done, the ATC of alternatives with offshore loading systems (Alternatives 2E and 2F) would be substantially reduced. Also, an offshore loading system without storage has a higher berth availability than one with a storage vessel.

5.8 SENSITIVITY ANALYSIS

In order to evaluate the effect of variations in the scenario parameters on the conclusions regarding the optimum transportation alternative, a number of sensitivity analyses have been carried out. The parameters varied for the analyses include:

- quantity of recoverable reserves (production rate),
- crude oil properties,
- distance to shore,
- water depth, and
- geotechnical conditions.

The effects of these variations on the individual transportation elements are discussed in the sections of this report in which the elements are described. This section is concerned with the effect on the overall transportation system alternatives for Scenario 2.

Appendix B contains tables which show the capital cost, annual operating cost and manpower required for each major transportation system element, for each alternative, and for each sensitivity parameter variation. The tables also list the present value of the total life cycle cost and the average transportation cost (ATC) of the crude oil for each case. They have been developed by fixing all scenario parameters but one at the base case values and setting the one parameter at a non-base case (sensitivity) value.

5.8.1 Recoverable Reserves

The base case recoverable reserves have been defined as 500 million barrels and the sensitivity values range from 100 million to two billion barrels. All size reservoirs have been assumed to perform in the same manner, as described in Section 3.3.2, with peak production rate equal to 9.1 percent of reserves.

Figure 5-15 presents the results of the recoverable reserves sensitivity analysis in the form of average crude oil transportation cost versus peak production rate. From the figure it is obvious that the transportation cost for each of the six alternatives considered is very sensitive to the production rate at rates below approximately 250,000 barrels per day. For all production rates considered, Alternative 2F, offshore loading and direct shipment to the West Coast, provides the lowest average transportation cost.

It is interesting to note that at low production rates Alternative 2D provides a lower ATC than Alternatives 2A, 2C and 2E, but at higher production rates the Alternative 20 ATC is higher than for Alternatives 2A and 2E.

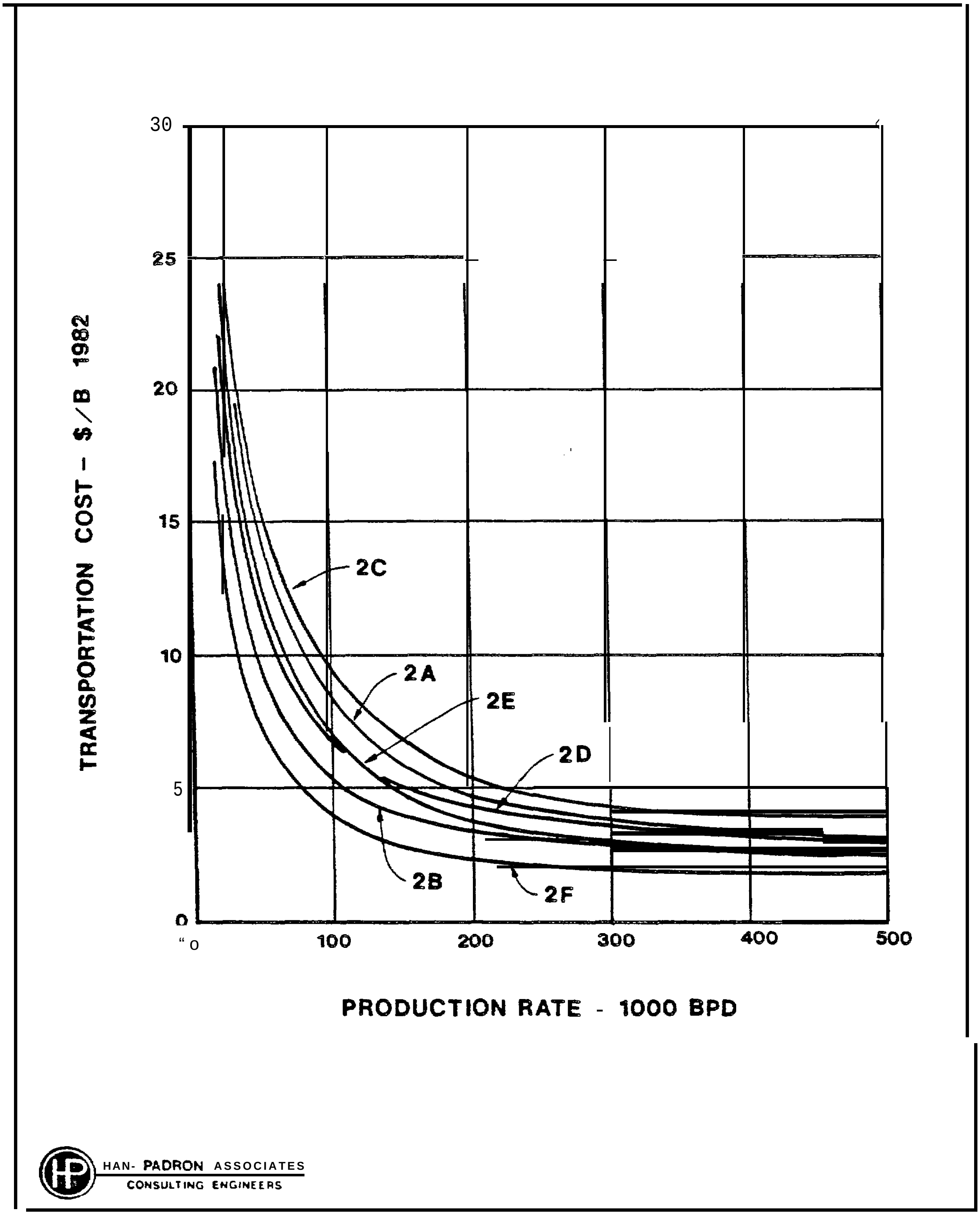

Figure 5-15. Scenario 2 crude oil transportation cost sensitivity to production rate.

5.8.2 Crude Oil Properties

The base case crude oil properties are quite suitable for transportation in either long pipelines or tankers. The sensitivity case crude oil has a relatively high pour point making pumping long distances under water impractical. For this type of crude, offshore loading alternatives are much more attractive than alternatives that require long pipelines.

The capital cost. of all alternatives considered would be higher for the sensitivity case crude. For long pipeline cases the costs would become prohibitive and no further analysis was conducted. For offshore loading cases, loading pipeline diameters and pumping horsepower would increase but the increase in total transportation system cost would be negligible. Alternatives requiring trans-shipment of the crude oil would become very unattractive because of reduction in temperature of the crude that would result from the unloading and loading operations.

5.8.3 Distance to Shore

Variations in the distance of the production platform from shore have virtually no effect on Alternatives 2E and 2F which have offshore storage and loading. For the other four alternatives the variation in the average transportation cost from the base case to the maximum or minimum distance cases ranges between 4 and 8 percent and has no effect on the conclusions reached.

5.8.4 Water Depth

The average transportation cost for Alternatives 2A through 2D are not affected by variations in water depth at the production site because these alternatives do not include an offshore terminal. The ATC for Alternatives for 2E and 2F are slightly sensitive to water depth within the range considered. The maximum variation in transportation cost is 3.5 percent or less and has no effect on the conclusions reached.

5.8.5 Geotechnical Conditions

As for water depth, variations of the seabed soil parameters affect only the offshore loading alternatives (2E and 2F). In both cases the ATC based on the superior soil conditions of the sensitivity case are reduced by less than 0.3 percent from the base case ATC and have no effect on the conclusions reached.

5.9 CONCLUSIONS

On the basis of cost, transportation Alternative 2F, offshore storage and loading and direct shipment to the West Coast, is the most preferable. For the base case peak production rate, Alternative

2F has a 23 percent lower average transportation cost than the next most efficient alternative. Considering the other factors as described in Section 5.7.2, Alternative 2F is equal to or more preferable than the other alternatives in every case except for the fact that tankers will have a greater distance to travel through ice than for alternatives with a pipeline to St. Paul Island and ice conditions around St. Paul Island will be somewhat less severe than at the offshore loading site. However, these exceptions are of minor importance and Alternative 2F is preferred on the basis of "other factors." Alternative 2F becomes especially attractive if the offshore crude oil storage can be provided within the production platform and the floating storage eliminated. Considering the sensitivity analyses described in Section 5.8, Alternative 2F is the most preferable on the basis of crude oil properties and there is not a significant difference among all the alternatives on the basis of the other sensitivity parameters.

Therefore, for the parameters as defined, Alternative 2F is the preferred method of transporting crude oil from the Central Bering Sea.

6.0 SCENARIO 3 - SOUTHERN BERING SEA

This chapter presents the technological and cost analysis of crude oil transportation systems for the Southern Bering Sea, the St. George and North Aleutian Basins Lease Sale areas. The site selected as representative of these areas is indicated in Figure 6-1. The location is based on what appears to be the center of the high interest tracts of the lease sale areas and is representative of the environmental conditions in the areas. All the pertinent characteristics of this scenario are defined and used in the evaluation of the transportation alternatives in the following sections. A number of the scenario parameters are varied to carry out sensitivity analyses.

6.1 ENVIRONMENTAL DESIGN CRITERIA

The background and basis for the selection of the environmental design criteria used for this study are described in Section 3.1. The specific design criteria for the Southern Bering Sea scenario are listed below.

6.1.1 Ice Conditions

The properties of sea ice listed below are based on a salinity of 7 ppt, an approximate weekly minimum average air temperature of

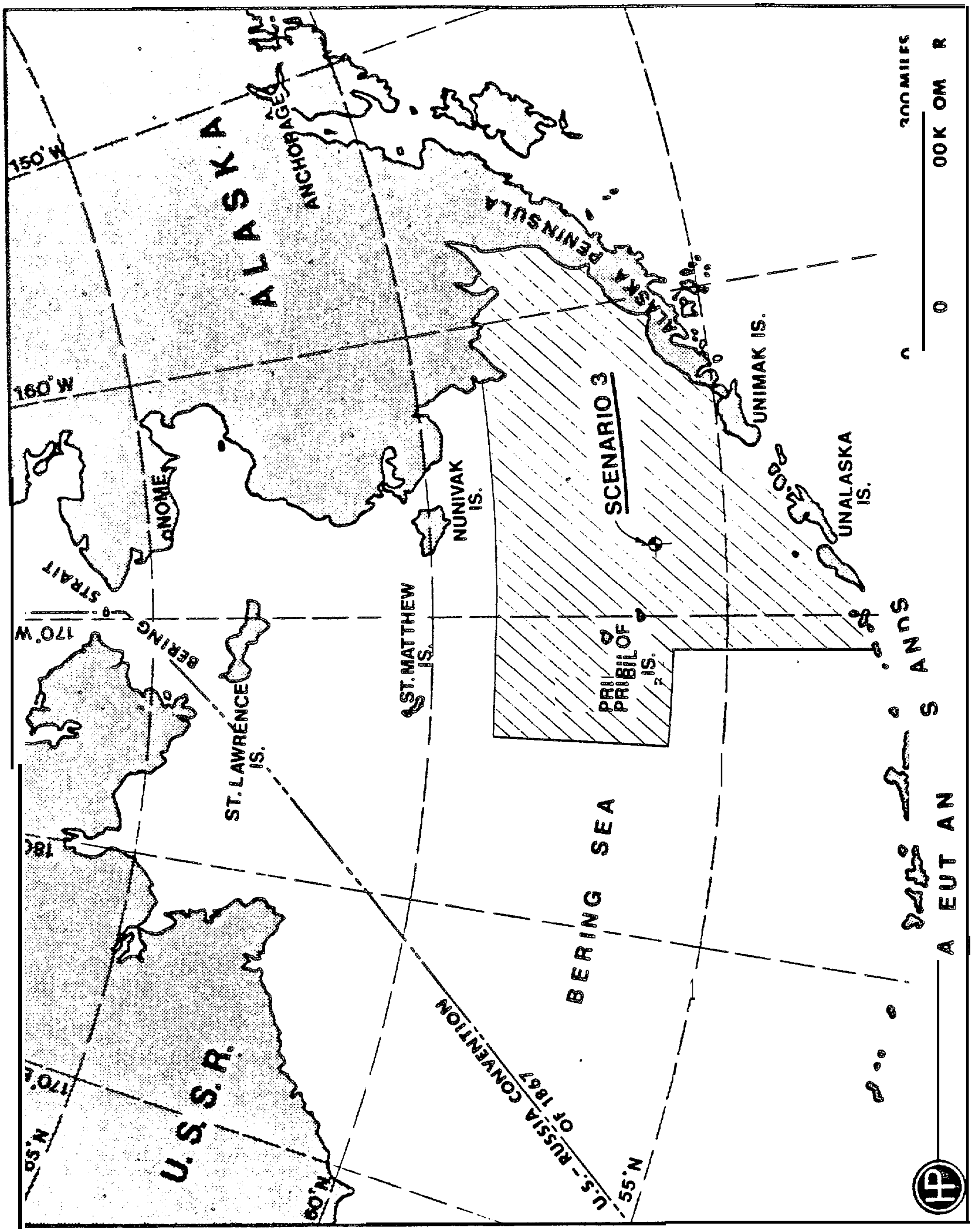

Figure 6-1. Location of Scenario 3.

-11 °C with a resultant average ice temperature of -2°C.

a) Ice Strengths

Compressive	=	2500 kPa (365 psi)
Flexural	=	275 kPa (40 psi)
Shear	=	500 kPa (75 psi)

b) Ice Modulus of Elasticity and Other Properties

Modulus of elasticity	= 1,025 mPa (150,000 psi)
Poisson's ratio	= 0.33
Density	= 935 kg/cu m (58 pcf)
Coefficient of friction	
ice/steel	= 0.15
ice/concrete	= 0.30

c) Level Ice Characteristics

Average thickness	= 0.6 m (2.0 ft)
Max. rafted thickness	= 1.2 m (4.0 ft)

d) Ice Ridges

	100 Year	1 Year
Sail height, m (ft)	2.1 (7.0)	1.4 (4.6)
Keel depth, m (ft)	6.7 (22,0)	4.5 (14.8)
Depth of consolidation, m (ft)	2.7 (9.0)	1.8 (5.9)

e) Ice Coverage and Concentration

Period of greater than 0% probability of ice coverage — February 1 to May 1

	Concentration (oktas)								
	0	1	2	3	4	5	6	7	8
Frequency of Occurrence (days per year)	276	0	0	13	0	46	0	30	0

f) Ice Floe Velocity

Max. ice floe velocity = 0.75 mps (1.5 knots)

g) Superstructure Icing Rate

Max. icing rate = 3.2 cm (1.25 in.) per 3 hr

6.1.2 Waves

Max. wave height = 29 m (95 ft)

Corresponding wave period = 16 sec

Wave crest elevation above still water level = 18 m (60 ft)

6.1.3 Water Depth

Base case = 125 m (410 ft)

Min. case = 100 m (328 ft)

Max. case = 150 m (492 ft)

6.1.4 Winds

Mean summer wind	= 5.5 to 8.5 mps (11 to 17 knots) from southeast through southwest
Mean winter wind	= 5.5 to 11 mps (11 to 22 knots) from northeast through northwest
Max. one-minute wind	= 50 mps (100 knots)
Max. three-second gust	= 60 mps (118 knots)
Max. one-hour wind	= 40 mps (78 knots)

6.1.5 Currents

Max. surface current	= 1.5 mps (3 knots)
Max. bottom current	= 0.25 mps (0.5 knots)

6.1.6 Tides/Storm Surge

Tidal range	= 1.0 m (3.3 ft)
Storm surge	= 1.0 m (3.3 ft)

6.1.7 Geotechnical Conditions

	Base Case	Sensitivity Analysis
Soil type	silty sand	silty clay
Friction angle, Ø	30°	0°
Shear strength, kPa (psf)	0	40 (800) @ mud line increasing @ 10 per meter of depth (60 per ft of depth)
Submerged unit weight, kg/cu m (pcf)	960 (60)	880 (55)

6.1.8 Seismic Conditions

API Seismic Zone	3
API Acceleration Factor	0.20

6.1.9 Meteorological Conditions

Average annual max. temperature = 5.0°C (41° F)

Average annual min. temperature = -0.8°C (31°F)

Average annual precipitation = 57.3 cm (22.6 in.)

AVERAGE ANNUAL PERCENT FREQUENCY OF OCCURRENCE OF PRECIPITATION TYPES

Rain or Drizzle	13.4
Freezing Rain or Drizzle	0.1
Snow or Sleet	11.3
Total Precipitation	24.8

AVERAGE ANNUAL PERCENT FREQUENCY OF OCCURRENCE OF REDUCED VISIBILITY

Fog	23.5
Smoke or Haze	1.8
Blowing Snow	3.5
Total Reduced Visibility	28.8

6.2 DESCRIPTION OF TRANSPORTATION ALTERNATIVES

Several reasonable alternatives exist for transporting crude oil from the Southern Bering Sea. Alternatives which have been discussed in previous studies, even if not considered practical, are included to provide a uniform basis for comparisons. The alternatives considered include:

Alternative 3A

Marine pipeline and land pipeline to an Alaska Peninsula nearshore terminal and conventional tanker to the U.S. West Coast (see Figure 6-2).

Alternative 313

Marine pipeline to a nearshore terminal on St. George Island, ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 6-3).

Alternative 3C

Marine pipeline to a nearshore terminal on St. George Island and ice-strengthened tanker to the U.S. West Coast (see Figure 6-4).

Alternative 3D

Offshore loading of ice-strengthened shuttle tanker to an Alaska Peninsula transshipment terminal and conventional tanker to the U.S. West Coast (see Figure 6-5).

Alternative 3E

Offshore loading of ice-strengthened tanker operating directly to the U.S. West Coast (see Figure 6-6).

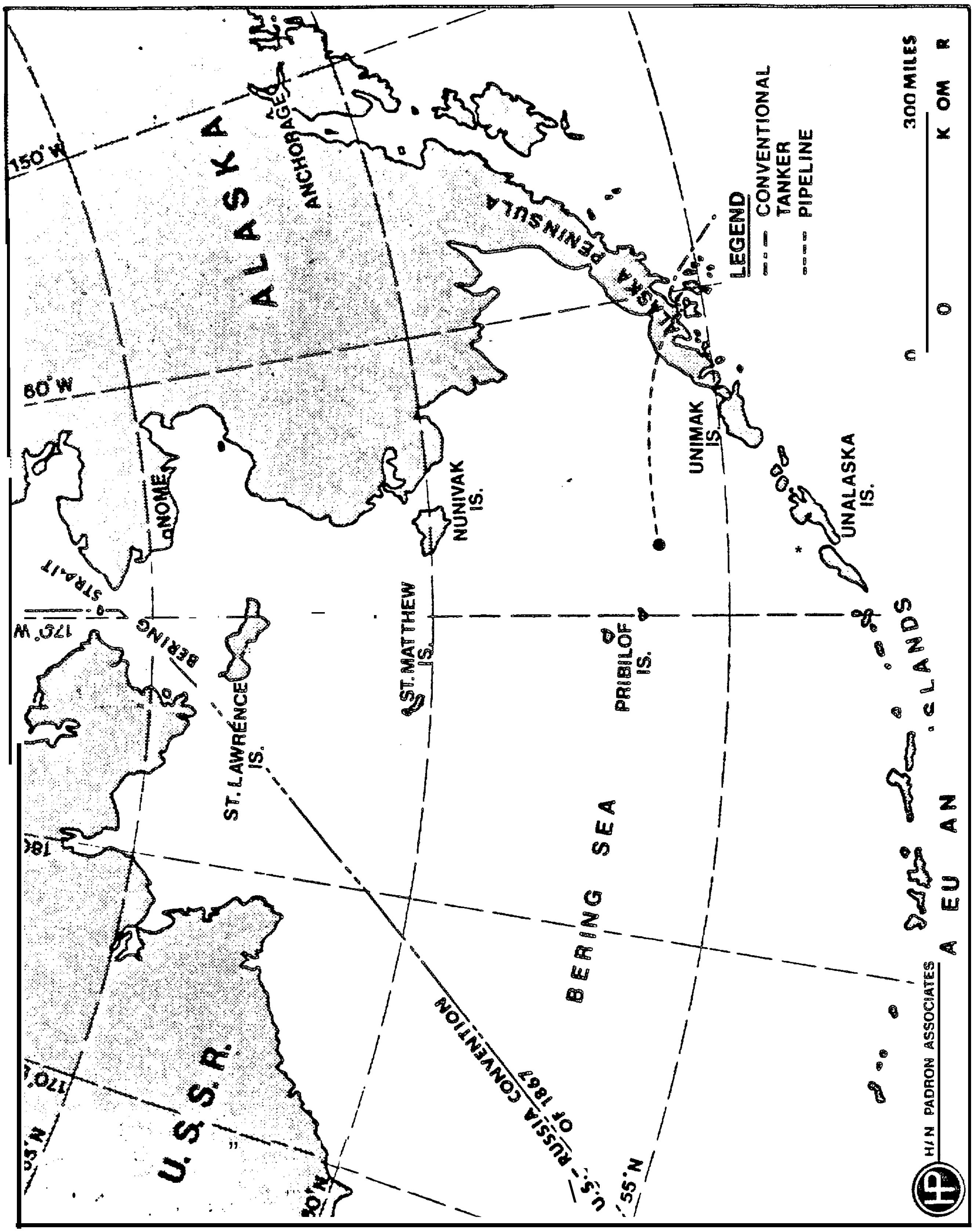

Figure 6-2. Scenario 3, Transportation Alternative A.

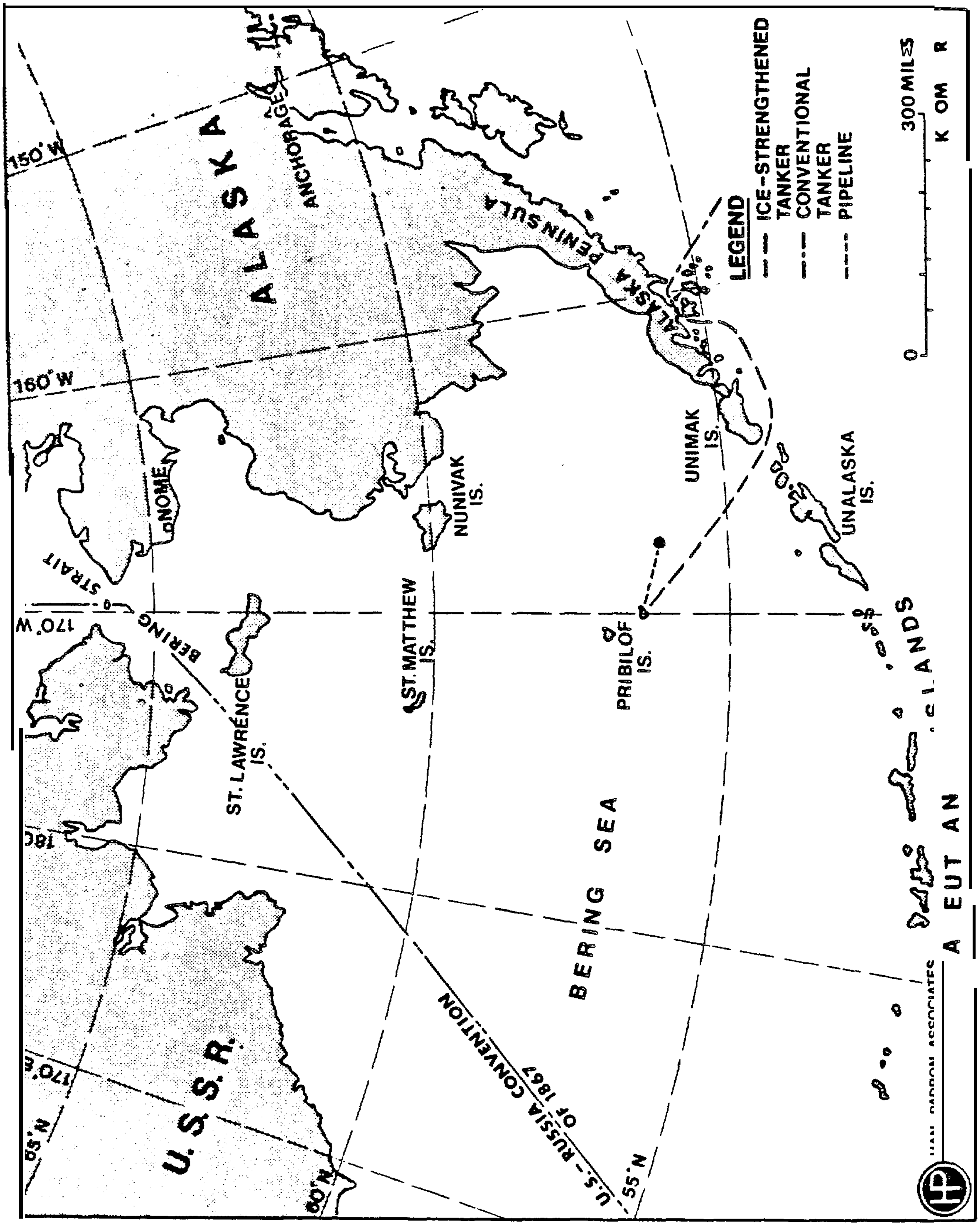

Figure 6-3. Scenario 3, Transportation Alternative B.

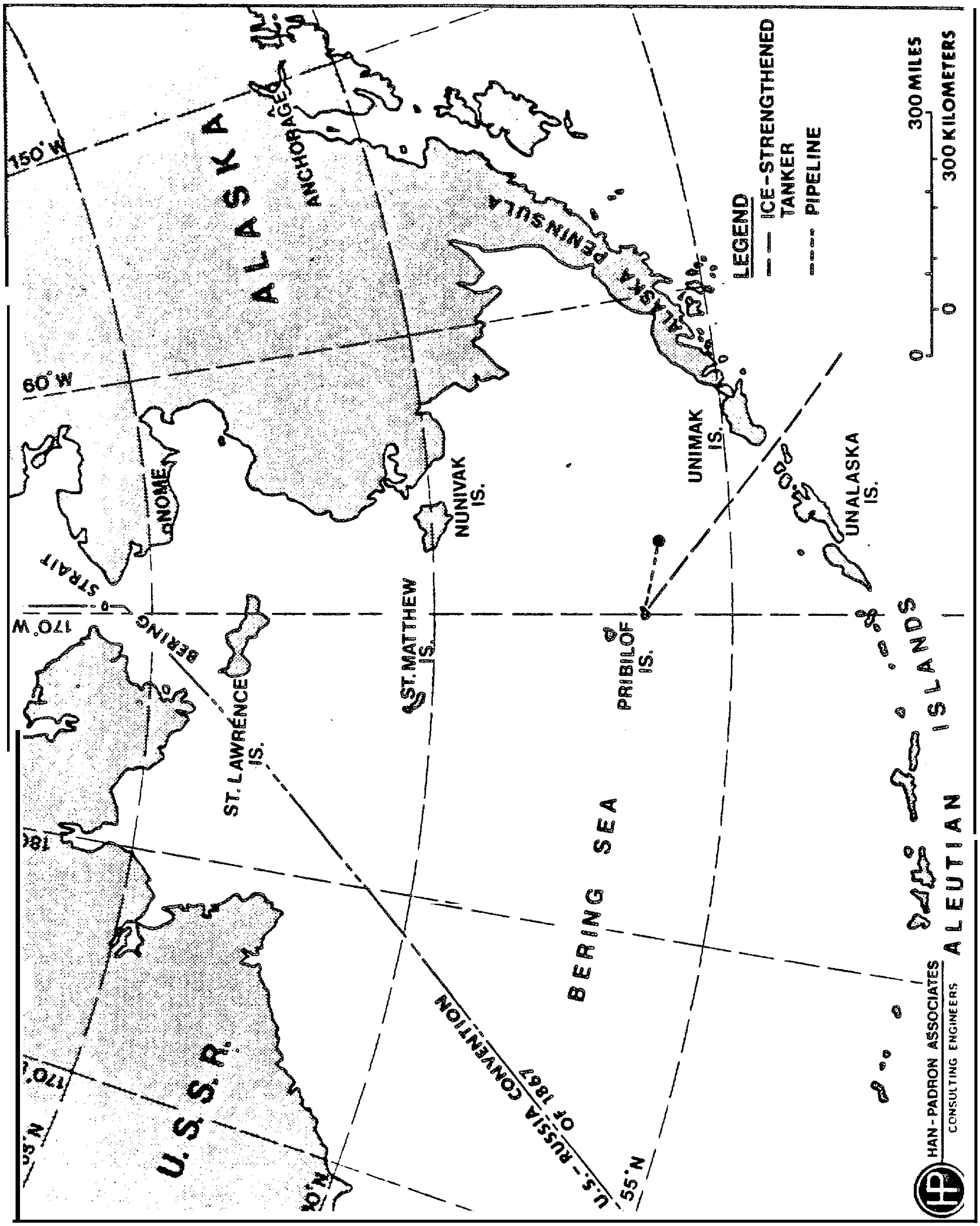

Figure 6-4. Scenario 3, Transportation Alternative C.

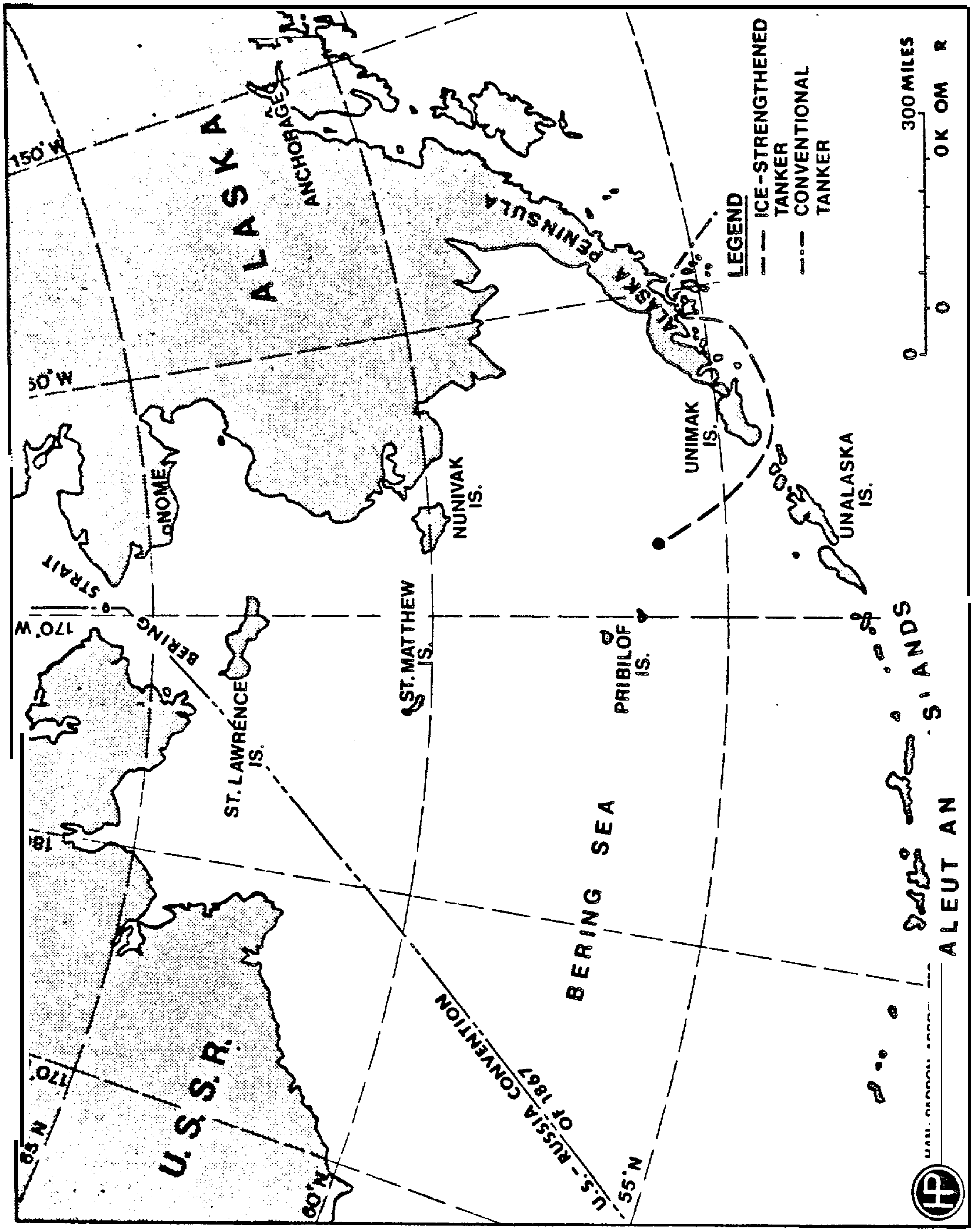

Figure 6-5. Scenario 3, Transportation Alternative D.

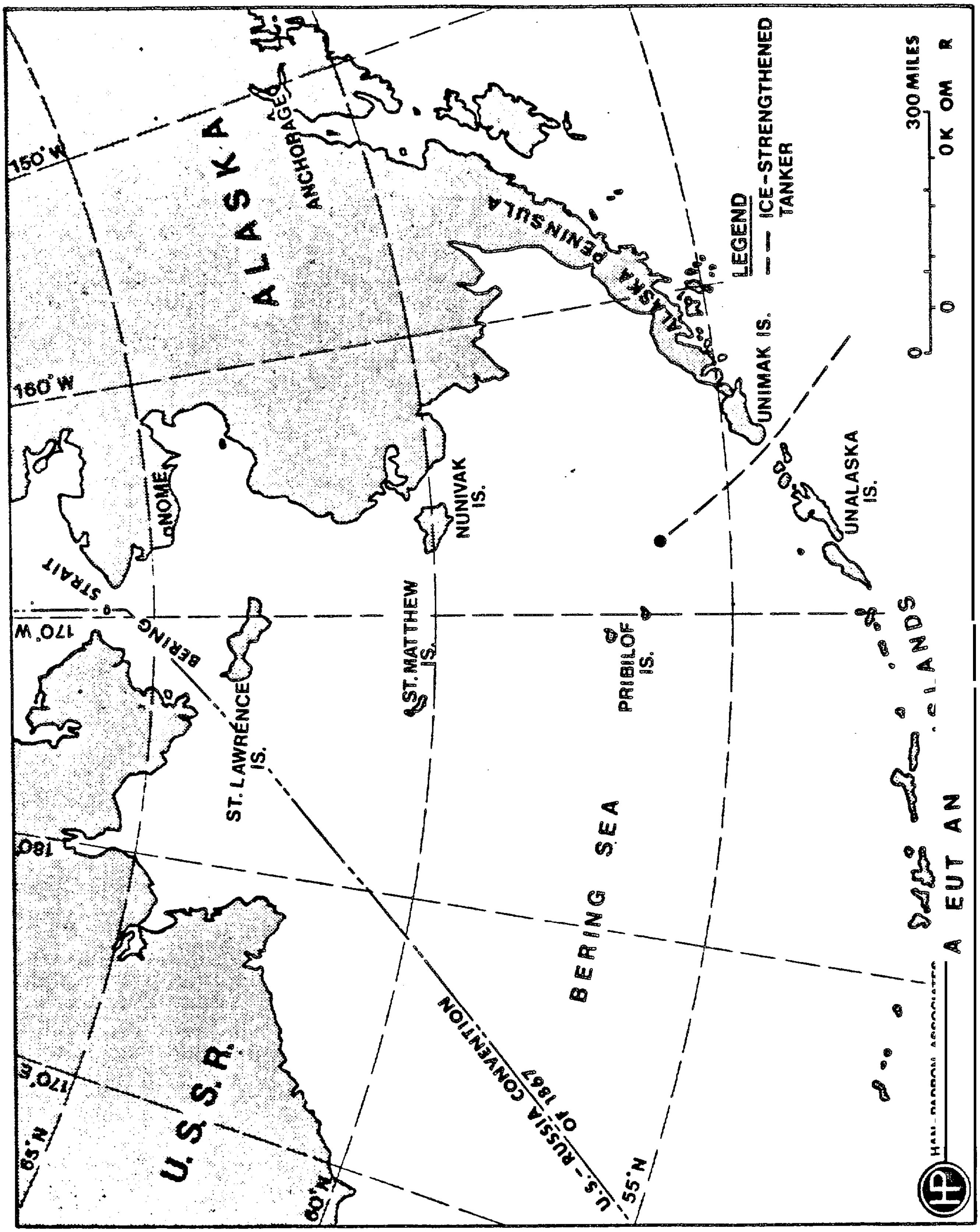

Figure 6-6. Scenario 3, Transportation Alternative E.

6.3 CRUDE OIL DESTINATIONS

For each of the "transportation alternatives listed in Section 6.2, base case pipeline lengths and tanker route lengths that have been used in the evaluation of the alternative are listed below. When minimum and maximum lengths have been used for sensitivity analyses they are also listed. Where any likely variation in a pipeline or tanker route length was less than ten percent of the base case length, no length sensitivity analysis was performed.

	LENGTH km (mi)		
	Base Case	Min. Case	Max. Case
Alternative 3A			
Marine pipeline	340 (210)	240 (150)	440 (275)
Land pipeline	60 (38)		
Conventional tanker route	3200 (1990)		
Alternative 3B			
Marine pipeline	120 (75)	20 (12)	220 (137)
Ice-strengthened tanker route	660 (410)		
Conventional tanker route	3200 (1990)		

<u>Alternative 3C</u>			
Marine pipeline	120 (75)	20 (12)	220 (137)
Ice-strengthened tanker route	3610 (2245)		
<u>Alternative 3D</u>			
Ice-strengthened tanker route	560 (350)	460 (285)	660 (410)
Conventional tanker route	3200 (1990)		
<u>Alternative 3E</u>			
Ice-strengthened tanker route	3510 (2180)		

6.4 OFFSHORE LOADING TERMINAL

The offshore loading terminal for Scenario 3 consists of a buoyancy stabilized articulated column type structure with a permanently moored floating crude oil storage vessel and a pipeline connecting the production platform to the storage/loading system. For alternatives that require two berths, an articulated columntype mooring and a pipeline connecting the mooring to the storage/loading system are provided. The elements of the offshore terminal are shown schematically in Figure 6-7.

For Scenario 3 the crude oil storage and tanker loading function are combined in a single facility featuring a permanently moored floating storage vessel to which tankers moor in tandem for loading.

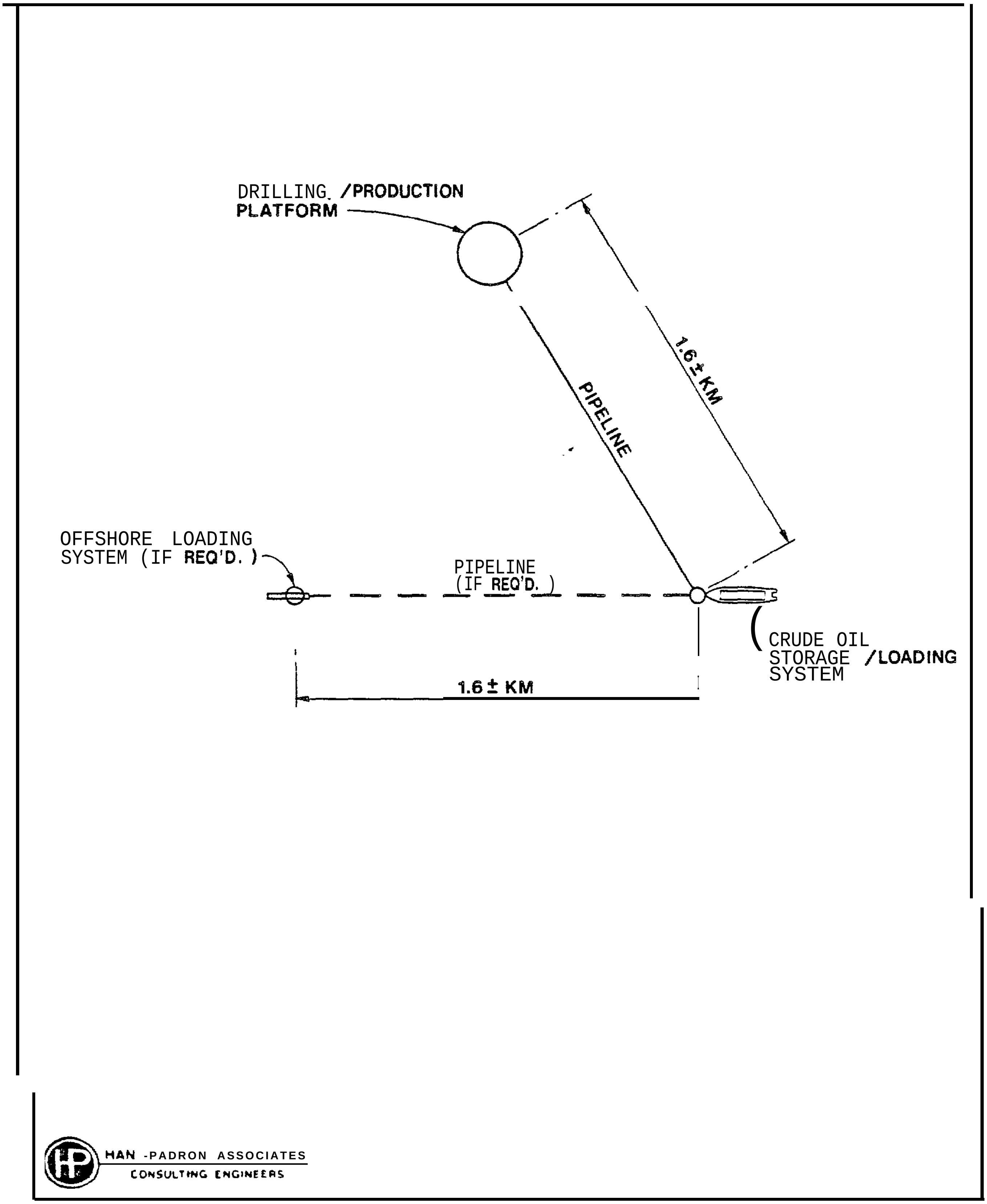

Figure 6-7. Scenario 3 schematic layout of offshore loading terminal.

For sensitivity analysis cases with very high production rates, two tanker loading facilities are required. In this case, the second loading system has no integral storage capacity but is connected to the storage vessel by means of a marine pipeline. As for the other scenarios, the crude oil storage facility is assumed to be separate from the drilling/production structure(s). However, if a large, gravity stabilized structure is used as the drilling/production platform, crude oil storage capacity could be incorporated in the platform at a significantly lower cost per barrel than for the floating storage, thus making transportation alternatives that utilize offshore crude oil storage more economically attractive than indicated in the following analyses.

Descriptions of the offshore storage/loading system and the offshore loading system are given below. The design philosophy for loading system aspects is given in Section 3.5.1 and for crude oil storage volume requirements in Section 3.5.4. Details regarding the pipelines are provided in Section 3.5.5.

6.4.1 Offshore Storage/Loading System

The optimum offshore storage/loading system for the Southern Bering Sea study area consists of a SPM tanker mooring with a permanently moored crude oil storage vessel. The deep water depths and ice condition require a unique offshore mooring concept capable of providing dependable year-round operation. After full evaluation of the alternative storage/loading system concepts feasible for operation in the southern portion of the Bering Sea based on the performance factors listed in Section 3.5.1, Figure 6-8 shows the concept selected to provide the requisite mooring, storage and loading facilities. The system consists of a buoyant articulated tower fixed to the seabed by a gravity/piled base with crude oil storage capacity provided by a floating storage vessel permanently yoke-moored to the tower. The system is similar to the offshore storage/loading system presently operating in the Fulmar Field in the North Sea. All power and manning requirements for operation of the terminal are located on the storage vessel. Since storage capacity requirements vary for the different alternatives considered, preliminary designs of the storage/loading system were prepared for a range of 0.5 million to 3.0 million barrels. It was found that, aside from the cost of the storage vessel, the variation in storage capacity had only minor effects on the design and cost of the system.

The buoyant tower concept was selected because it most efficiently resists the environmental ice loading while utilizing proven technology in structural and mechanical component design, and also provides established procedural guidelines for mooring and loading operations based on previous North Sea experience. Alternative concepts evaluated included:

- buoyant articulated tower with submerged loading/ mooring system,

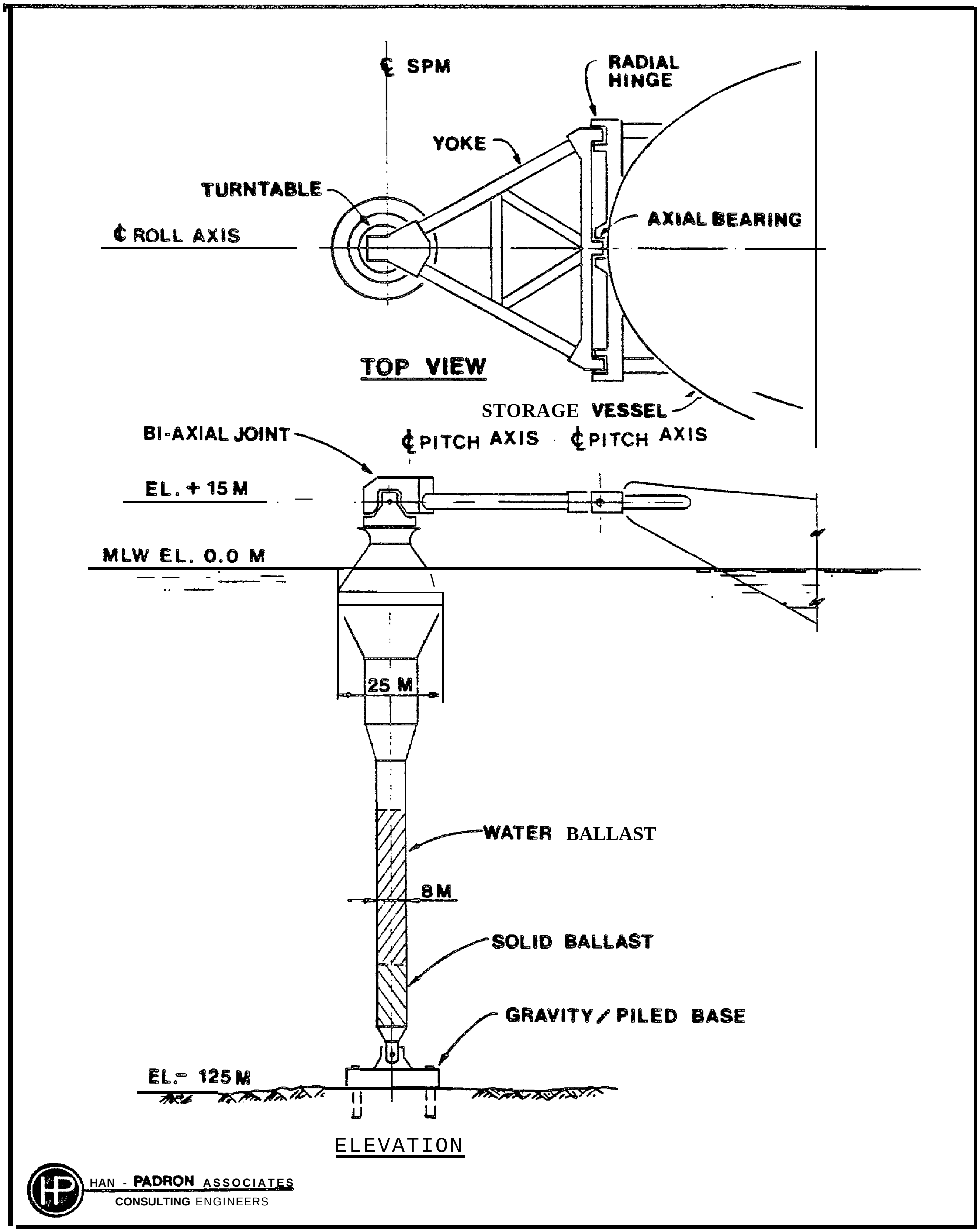

Figure 6-8. Scenario 3 offshore storage/loading system.

- catenary chain stabilized articulated tower,
- catenary chain moored tanker turret system,
- multiple articulated single anchor leg mooring system,
- catenary chain moored spar buoy,
- all of the above with bottom founded submerged storage in place of a floating storage vessel, and
- fixed, rigid gravity structure with integral storage.

Systems utilizing submerged, bottom founded storage appear to be approximately equal in cost to the floating storage vessel concept for the smaller storage capacities, but increase more rapidly with increasing capacity. Other reasons the floating storage concept was deemed preferable include:

- the segregated ballast system on the floating storage unit eliminates the need to discharge treated ballast water into the sea (A submerged storage system, in order to be of reasonable cost, must utilize a seawater/crude oil displacement system and the ballast water will require treatment before discharge.),
- maintenance and operating procedures on a tanker-like vessel are well established and proven while this is not true for a submerged storage system, and
- bottom founded storage structure feasibility is highly dependent on site-specific soil conditions, whereas floating storage is not.

Ice and wave loading govern the design of the storage/loading system. The environmental design criteria is given in Section 6.1 and the procedures for establishing the design forces are presented in Section 3.2. Ice forces acting on the loading terminal consist of icebreaking and clearing components on the SPM tower and on the permanently moored storage vessel. Considering that peak loads from sheet ice and pressure ridge failure and clearing mechanisms are not simultaneous, the governing total ice force on the tower and storage vessel was calculated to be 1400 t (3,200,000 lb). This force occurs when the sheet ice is breaking and clearing around the conically-shaped articulated tower and the design pressure ridge is being cleared around the storage vessel (sized for 3.0 million barrels storage capacity). By comparison, the ice force on the 0.5 million barrel storage system was calculated to be 1200 t (2,700,000 lb). The ice loading governs the volume of buoyancy provided in the tower, the" size and cost of the mechanical hinge and bearing systems, and the local design of the tower cone and ice-strengthened band on the storage tanker. The dynamic wave loading on the system governs the design of the tower structure and the foundation system. The maximum horizontal wave force on the system is estimated to be 4000 t (8,900,000 lb) with 1100 t (2,500,000 lb) of the total applied to the foundation and the remaining force resisted by the restoring characteristics of the tower and the damping characteristics of the storage vessel. The dynamic wave loading also causes the maximum vertical forces throughout the tower and especially affects the design of the base articulation and foundation piling.

The limiting factor for the use of the buoyant articulated tower concept is the maximum restoring force of the system. The total ice force on the buoyant tower system represents approximately 90 percent of the practical limit of the restoring force for the given water depth. For greater ice forces, a catenary restoring force system, similar to that of Scenario 2, would be required. The vertical surface of a 9 m (30 ft) diameter cylinder requires approximately fifteen times the force to fail the design sheet ice as does the conical surface. Without the cone attachment, neither the selected concept, nor one utilizing catenary chains, would be capable of resisting the design ice forces, thus making the cone an essential part of the structure.

The single piece tower structure extends 15 m (50 ft) above still water level to the yoke frame centerline. The icebreaker cone extends 5.5 m (18 ft) both above and below the waterline. From the cone's base width of 25 m (80 ft), it reduces to 12 m (40 ft) on a 1:2 slope and remains at 12 m for a length of 15 m (50 ft) after which it reduces to a shaft diameter of 8 m (25 ft). The shaft extends down to within the final 6 m (20 ft) where it reduces to mate with the hi-axial universal joint secured to the base structure.

The tower is divided into ten watertight compartments by horizontal bulkheads. The number and spacing of the compartments assures that the tower remains stable and operational during an accidental occurrence of two adjacent compartments flooding. In addition, all exterior compartments adjacent to the conical shell may be flooded as a result of plate puncture or rupture without affecting tower operation. Local design of the icebreaker cone provides for ice pressures over small areas up to 5.2 mPa (750 psi). The cylindrical shaft is stiffened by circumferential ring stiffeners to meet. axial compression and hydrostatic collapse interaction criteria. All stresses throughout the structure are kept below the fatigue governing values.

The turntable is attached to the 9 m (30 ft) diameter upper tower shaft by a large diameter three-roller bearing. The turntable is protected from ice ride-up by a deflector shield fitted above the cone. The large ice force transferred to the tower from the moored storage vessel, approximately 1020 t (2,250,000 lb), may be resisted by a yoke arrangement of bearings and hinges within the technological range of similar systems currently in use. The turntable provides vertical and radial support for the yoke tip while permitting the vessel to weathervane about the mooring structure in compliance with prevailing environmental conditions. A set of radial hinges, at the vessel end of the yoke, and a hi-axial hinge on the turntable, permit the storage vessel to heave, pitch and roll without applying forces to the tower. An axial bearing at the vessel end of the yoke isolates tangential loads from the two adjacent radial hinges.

The large amount of buoyancy required in the tower to provide the needed restoring force also necessitates a large amount of weight to maintain its stability or fixity to the seabed. The design philosophy has been established such that no tension exists in the base foundation piles during ice-free periods coupled with the average conditions of wind and wave forces on the storage/loading system. To accomplish this, a substantial amount of solid ballast is required in both the lower portion of the tower and in the base structure. In addition, water ballast is required in most of the tower shaft. The piled foundation is designed to support the net weight of the structure during environmentally calm periods and to act in tension during application of the design environmental forces.

The storage vessel is similar in design to icebreaker tankers except for the minimal power requirements. Mooring of the ice-strengthened tankers will occur in tandem with the wider storage vessel, which will provide a relatively ice-free approach lead for the tanker during most conditions of heavy ice coverage and keep ice forces transferred through the mooring lines to readily manageable levels. A more detailed discussion of the storage vessel is provided in Section 5.4.1. Figure 6-9 shows the tandem mooring arrangement.

'The capital cost for the offshore storage/loading system versus water depth is shown in Figure 6-10 for the case of 1.0 MMB storage capacity. The increase in capital cost with water depth is only dependent 'on the increased cost of the lengthened tower. The

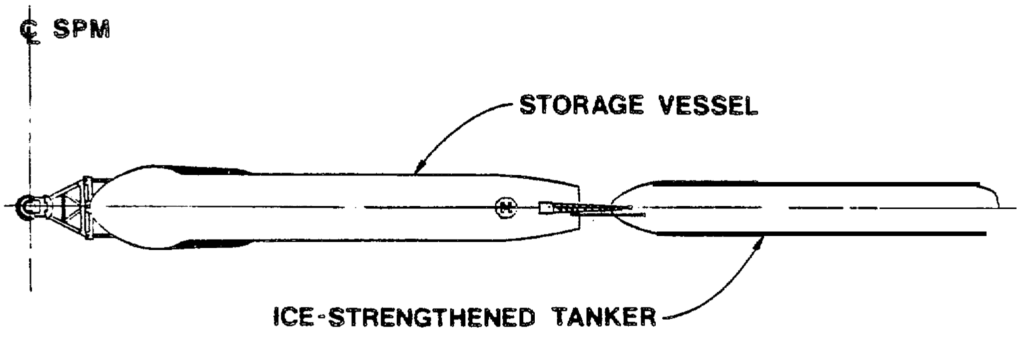

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Figure 6-9. Scenario 3 offshore storage/loading system tandem mooring configuration.

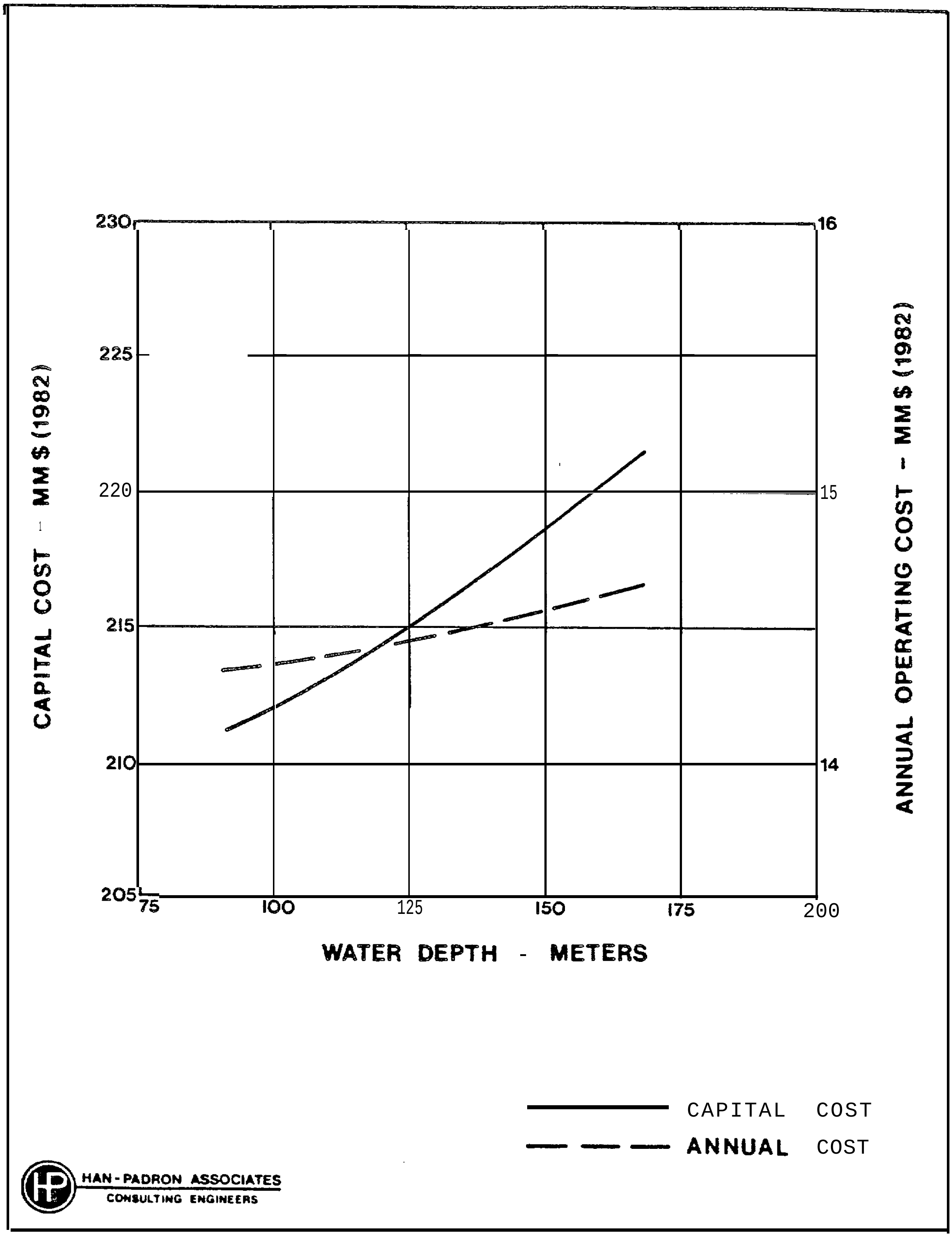

Figure 6-10. Scenario 3 offshore storage/loading system capital and annual costs versus water depth.

floating storage vessel, accounting for 75 percent of the 1.0 MMB storage/loading system cost, is unaffected by varying water depth and tends to stabilize the total percentage of cost fluctuation. Ice forces on the system are also unaffected by increasing water depth, however, the restoring force characteristics of the tower are favorably influenced by the deeper water and thus results in greater overall system efficiency.

The base case soil condition for the southern study area, as discussed in Section 6.1, is composed of silty sand and has been used to determine the required foundation systems contributing to the capital cost shown for all other sensitivity functions. The alternative soil consists of cohesive material which is not as well suited for the specific foundation application as is the base case soil. However, the foundation cost of the selected storage/loading system is relatively small in comparison to the cost of the other components and the poorer soil condition results in less than a 0.5 percent increase in the total capital cost of the system.

Capital cost versus storage capacity is given in Figure 6-11 for the storage/loading system at the base case water depth. Almost the total variation in capital cost in this instance is attributable to the cost of the floating storage vessel. The increase in storage vessel size results in slightly higher ice loading on the system but negligibly influences the cost of the tower structure. Of the total cost increase resulting from increased storage capacity, less than 2

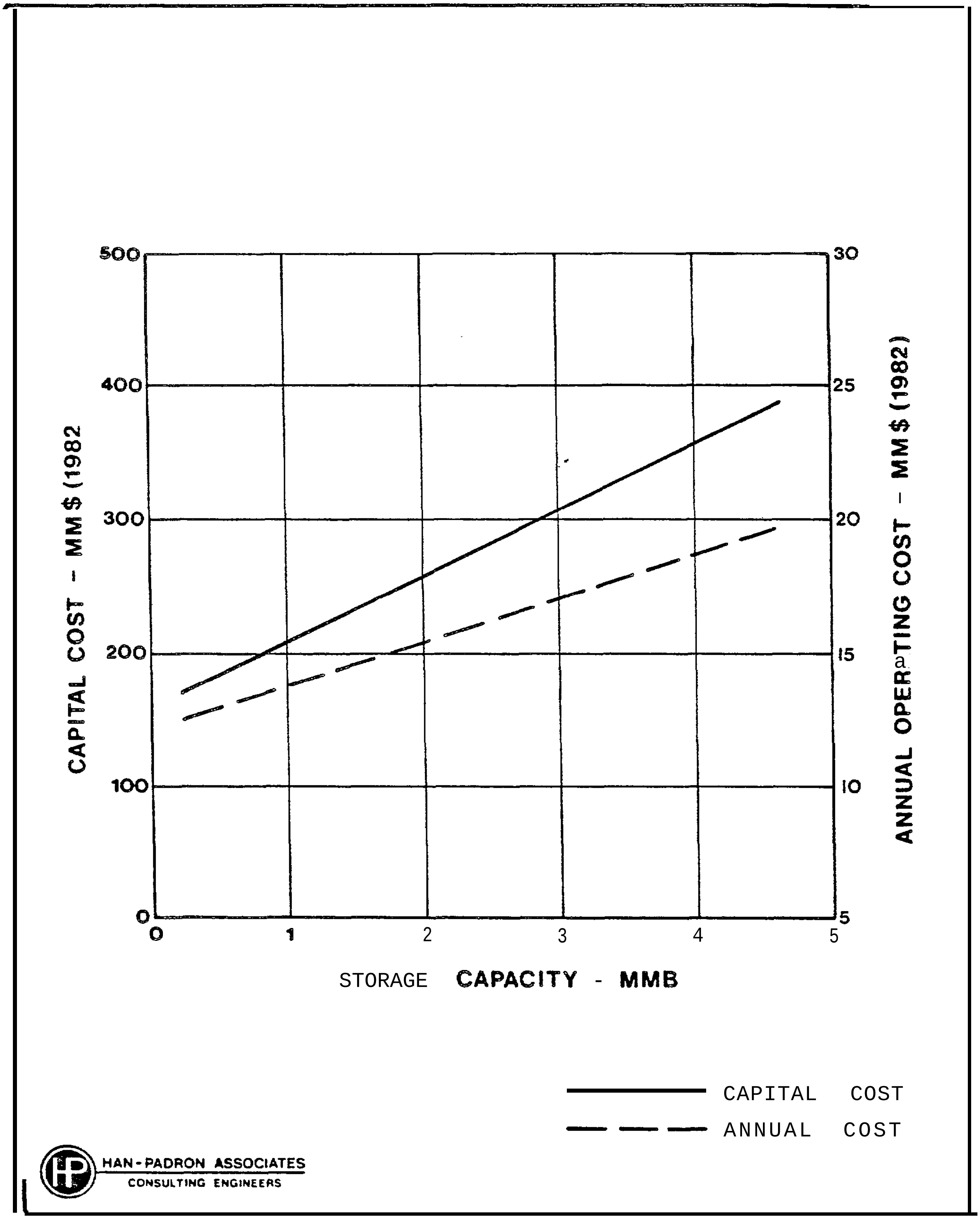

Figure 6-11. Scenario 3 offshore storage/loading system capital and annual costs versus storage capacity.

percentis due to increase in the tower structure cost and the remainder due to increase in the storage vessel cost.

Annual operating and maintenance cost for the offshore storage/loading system has been established on the basis of the operating manpower cost plus 3.0 percent of the capital cost. The annual cost is shown in Figure 6-10 versus water depth and Figure 6-11 versus storage capacity.

The manpower required to operate and maintain the offshore storage/loading system is estimated to be 40 men times a rotation factor of two.

The berth availability rate, as defined in Section 3.5.2, has been established for the Scenario 3 offshore storage/loading system based on the criteria listed in Section 3.5.2, and summarized as follows:

- Ice and visibility conditions will not limit mooring operations.
- Mooring operations will take place in seas with a significant wave height of 3.0 m (10 ft).
- Unscheduled maintenance causes 5 percent maintenance downtime.

The average frequency of occurrence, over the worst three consecutive months, of significant wave heights exceeding 3.0 m (10 ft), based on wave height threshold data contained in "Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska" (Brewer et al. 1977), is approximately 31 percent. Allowing for 5 percent unplanned maintenance downtime, the berth availability rate of the offshore storage/loading system for this scenario is 64 percent.

6.4.2 Offshore Loading System

Some of the transportation alternatives considered require only one tanker loading berth while other alternatives require two. Where one berth is required it consists of the offshore storage/loading system described above. Where a second berth is required it contains no crude oil storage capacity. A pipeline connects the second tanker berth to the adjacent storage/loading system as illustrated schematically in Figure 6-7.

The concept development and selection for the optimum offshore loading system without storage capacity for Scenario 3 followed the same evaluation procedure as for the storage/loading system. The selected offshore loading system without storage capacity for the Southern Bering Sea study area is shown in Figure 6-12. The system consists of a buoyant articulated tower fixed to the seabed by a gravity/piled base. Buoyancy in the tower provides the restoring force required to resist the environmental loads resulting from wind, wave, ice and current acting on the tower and the moored tanker.

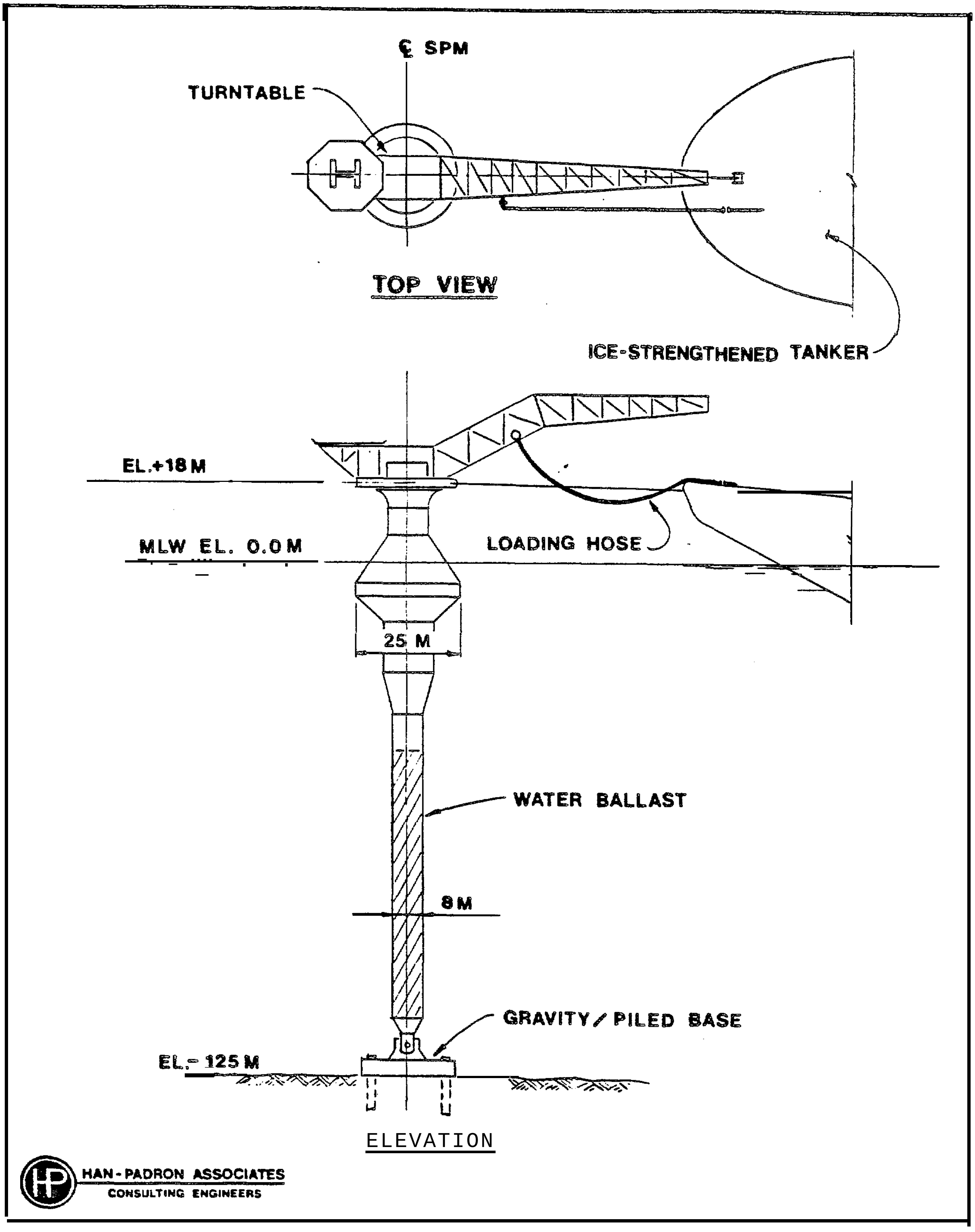

Figure 6-12. Scenario 3 offshore loading system.

Power and manning requirements for operation of the loading berth are located on the tower turntable above the wave zone. Preliminary designs on which the cost analyses are based have been prepared for various water depths and seabed geotechnical conditions. The variation in ice-strengthened tanker size for the transportation alternatives requiring a second loading berth negligibly affects the cost of the systems, Therefore, a tanker size of 150,000 DWT was utilized for the pre"liminary designs and a tanker size sensitivity analysis omitted.

Ice and wave loading govern the design of the offshore loading system. Section 6.1 contains the environmental design criteria utilized and Section 3.2 outlines the procedures followed in establishing the environmental design forces on the system. Ice forces consist of breaking and clearing components on both the tower and ice-strengthened tanker. The tower, without a moored tanker, is designed for the 100 year maximum ice feature or wave condition. During periods of tanker mooring and loading operations, the design ice feature criteria is reduced to a 1 year recurrence interval. The design wave height is also reduced to the maximum established for safe loading operations. If ice or wave conditions exceed these reduced limits, the tanker will cast-off. After evaluation of all appropriate combinations of simultaneous peak ice loads on the tower and tanker, the governing total ice force on the offshore loading system was calculated to be approximately 740 t (1,600,000 lb). This loading occurs for the combination of the 1 year sheet ice thickness breaking and clearing on the conical skirted tower and the 1 year ice ridge clearing the moored tanker. The force on the tanker accounts for approximately 60 percent of the total force on the system. The mooring hawsers will be required to transfer the 440 t (970,000 lb) ice force acting on the tanker to the tower. This force is at the upper limit of the capacity of conventional mooring hawser systems and will pose no special problems.

The ice forces govern the design of the restoring characteristics of the tower (volume of buoyancy), the local design of the cone, the turntable bearing systems and the mooring hawsers. The dynamic wave load condition, without the tanker moored to the tower, governs the design of the tower shaft and foundation. The maximum total horizontal wave force on the structure is approximately 2700 t (6,000,000 lb). This is less than the force on the storage/loading system due to the increased tower compliancy that results from the absence of the damping influence of the permanently moored storage vessel and the smaller enclosed volume in the upper structure. However, a greater portion of the horizontal force, 1500 t (3,300,000 lb), is applied to the foundation of the offshore loading system. Vertical wave forces are comparable to those acting on the storage/loading system.

As discussed above, the addition of the icebreaking cone is required to reduce the peak ice forces acting on the system. The main tower shaft extends from the turntable at the top, through the cone attachment, and connects to the hi-axial universal joint secured to the base structure. Details of the main tower are similar to those of the storage/loading system tower described in Section 6.4.1.

The turntable is attached to the tower shaft by a large diameter slew bearing arrangement that permits the moored tanker to weathervane about the mooring in compliance with the prevailing environmental conditions. Living quarters and power generation equipment are located on the turntable deck and within the main tower shaft. A heliport is fixed on top of the turntable boom which supports the loading hoses and messenger lines.

The capital cost for the offshore loading system in the southern study area is given in Figure 6-13 versus water depth. The increase in capital cost with water depth results from the increase in the length of the tower.

As discussed for the storage/loading system, the alternate sensitivity case soil results in a less favorable foundation condition and increases the total capital cost of the system by less than one percent over the base case capital cost.

Annual operating and maintenance cost for the offshore loading system is estimated to be approximately $4.0 million. The manpower required to operate and maintain the system is estimated to be 10 men times a rotation factor of two.

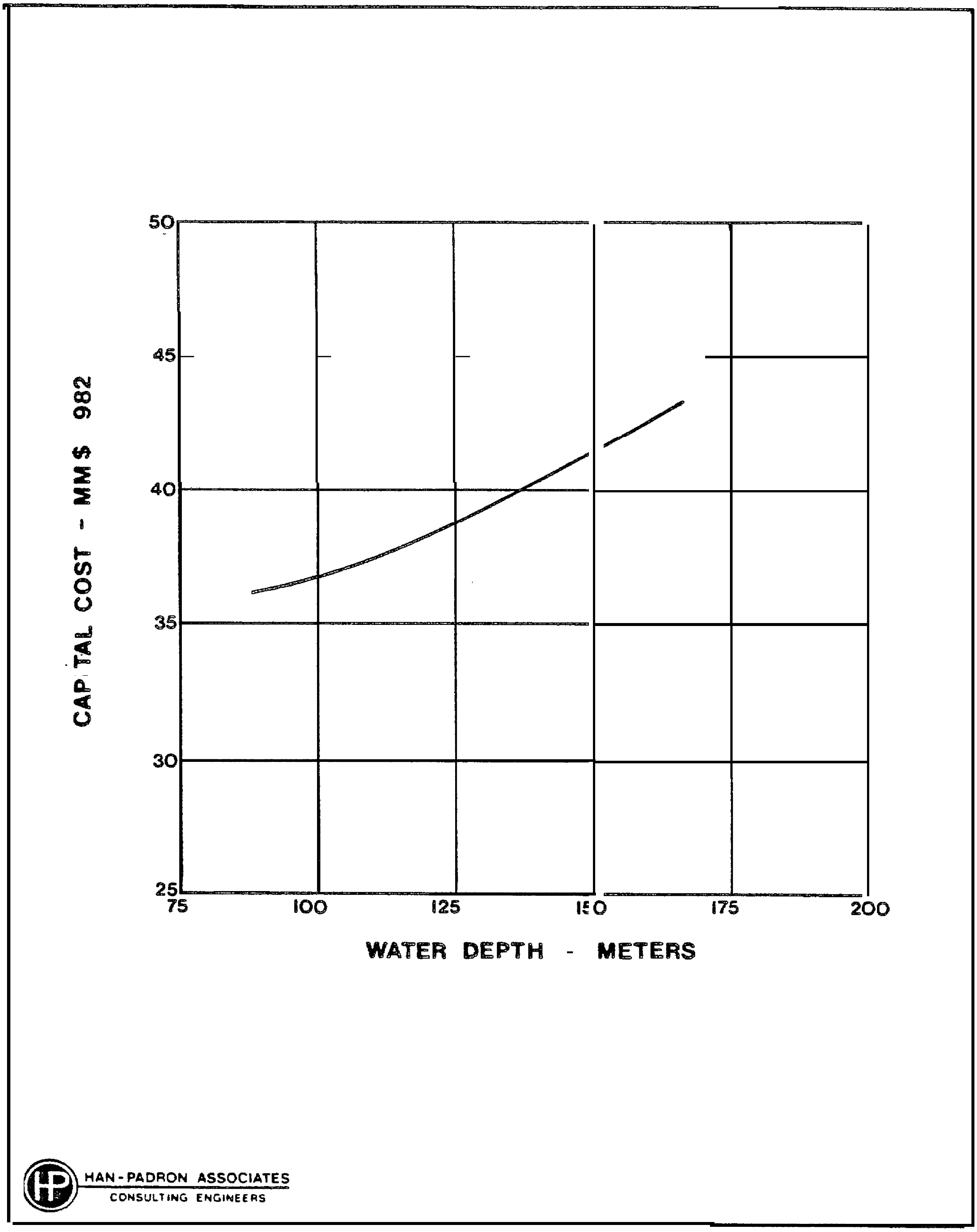

Figure 6-13. Scenario 3 offshore loading system capital cost versus water depth.

The berth availability rate for the offshore loading system is based on the same criteria as described above for the offshore storage/loading system except that the significant wave height in which mooring operations can take place is increased to 4.0 m (13 ft). The average frequency of occurrence of waves with a significant height greater than 4.0 m (13 ft) in the worst three consecutive months is approximately 23 percent. Allowing for 5 percent unplanned maintenance downtime, the berth availability rate is 72 percent.

6.5 NEARSHORE LOADING TERMINAL

Two types of nearshore loading terminals are considered for Scenario 3, one on St. George Island and one in Balboa Bay. The nearshore terminal on St. George Island will be essentially the same as the Scenario 2 nearshore terminal described in Section 5.5. The nearshore terminal in Balboa Bay will be similar to the transshipment terminal in Balboa Bay described in Section 3.5.1 c).

6.6 OPTIMIZATION OF TRANSPORTATION ALTERNATIVES

The optimum size/number/capacity of each of the transportation system elements of each of the five Scenario 3 alternatives, based on the base case scenario parameters, are listed in Table 6-1. The

TABLE 6-1

SCENARIO 3 OPTIMUM TRANSPORTATION SYSTEM ELEMENTS

TRANSPORTATION ELEMENT	ALTERNATIVE 3A	3B	3C	3D	3E
Ice-strengthened Tankers					
Ice Class		1	1	1	1
Size (MDWT)		44	140	40	137
Number		2	2	2	2
Icebreakers					
Ice Class		2	2	2	2
Number		2	2	2	2
Conventional Tankers					
Size (MDWT)	127	127	-	127	
Number	2	2	-	2	
Offshore Loading Terminal					
Berth Occupancy Rate (%)			-	34	20
Number of Berths			-	2	1
Storage Capacity (MMB)			-	0.6	1.3
Loading Ppl Dia (in.)			-	26	26
Nearshore Loading Terminal					
Berth Occupancy Rate (%)	17	28	17		
Number of Berths	1	2	1		
Storage Capacity (MMB)	1.6	0.6	1.3		
Loading Ppl Dia (in.)	36	28	38		
Transshipment Terminal					
Berth Occupancy Rate (%)		35	-	35	
Number of Berths		2	-	2	
Storage Capacity (MMB)		1.6	-	1.6	
Load./Unload. Ppl Dia (in.)		36	-	36	
Marine Pipeline					
Diameter (in.)	24	18	18		
Length (km)	340	120	120		
Land Pipeline					
Diameter (in.)	24		-		
Length (km)	60		-		

optimum size and number of ice-strengthened and conventional tankers have been developed as described in Section 3.4.1. The ice class of escort icebreakers has been developed as described in Section 3.4.4. The berth occupancy rates and number of berths for each type of terminal have been developed as described in Section 3.5.3. The optimum storage capacity for each type of terminal has been developed as described in Section 3.5.4. The loading pipeline diameter has been developed as described in Section 3.5.5. The marine pipeline diameter and length have been developed as described in Section 3.6 and the land pipeline diameter and length as described in Section 3.7.

6.7 COMPARISON OF TRANSPORTATION ALTERNATIVES

Each "Scenario 3 crude oil transportation alternative has been compared on the basis of total cost over the life of the reservoir, based on a discount rate of 8 percent, as described in Section 6.7.1. The various alternatives have also been compared based on factors other than cost, such as, construction logistical and timing problems, environmental factors and reliability, as described in Section 6.7.2.

6.7.1 Cost

The total cost of the crude oil transportation system over the life of the reservoir, which has been assumed to be 15 years, has been calculated for each alternative and the results are presented in Tables 6-2 through 6-6. The tables show the capital cost for each major transportation system element, the characteristics of which are listed in Table 6-1. For each element, the annual operating cost, during a peak production year, is also shown, as is the manpower required to operate the element. The manpower figures presented are the crew size times a "shift factor" and times a "rotation factor." Tanker crews are not included.

The present value of the total life cycle cost is listed at the bottom of the tables. These figures are based on constant January 1982 dollars and an 8 percent discount rate. The effect of taxes or royalties is not included.

To obtain the average transportation cost (ATC) of the crude oil, on a per barrel basis, the present value of total cost is divided by the total volume of oil produced over the 15 year life of the reservoir.

Transportation alternative 3E results in the lowest ATC for Scenario 3.

6.7.2 Other Factors

There are a number of factors, other than costs, which may

TABLE 6-2

TRANSPORTATION ALTERNATIVE 3A

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	---	---	Excl
ICEBREAKERS	---	---	...
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	---	---	...
NEARSHORE LOADING TERMINAL	333	19	120
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	535	19	---
LAND PIPELINE	276	10	---
TOTAL	1398	74	120

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2070

AVERAGE TRANSPORTATION COST PER BARREL = $ 4.83

TABLE 6-3

TRANSPORTATION ALTERNATIVE 3B

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	260	28	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	...	...	---
NEARSHORE LOADING TERMINAL	419	21	140
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	154	5	---
LAND PIPELINE	---	---	---
TOTAL	1590	115	380

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2630

AVERAGE TRANSPORTATION COST PER BARREL = $ 6.13

TABLE 6-4

TRANSPORTATION ALTERNATIVE 3C

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	336	34	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL	---	---	---
NEARSHORE LOADING TERMINAL	366	18	120
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	154	5	---
LAND PIPELINE	---	---	---
TOTAL	936	69	220

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 1560

AVERAGE TRANSPORTATION COST PER BARREL = $ 3.63

TABLE 6-5

TRANSPORTATION ALTERNATIVE 3D

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	256	28	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	254	26	Excl
OFFSHORE LOADING TERMINAL	266	17	100
NEARSHORE LOADING TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	423	23	140
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	1279	106	340

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 2230

AVERAGE TRANSPORTATION COST PER BARREL = $ 5.21

TABLE 6-6

TRANSPORTATION ALTERNATIVE 3E

COSTS AND MANPOWER REQUIREMENTS

TRANSPORTATION ELEMENT	CAPITAL COST MM$	ANNUAL COST MM$	MANPOWER man-yr
ICE-STRENGTHENED TANKERS	332	34	Excl
ICEBREAKERS	80	12	100
CONVENTIONAL TANKERS	---	---	Excl
OFFSHORE LOADING TERMINAL	237	14	80
NEARSHORE LOADING TERMINAL	---	---	---
TRANSSHIPMENT TERMINAL	---	---	---
MARINE PIPELINE	---	---	---
LAND PIPELINE	---	---	---
TOTAL	649	60	180

PRESENT VALUE OF TOTAL COST (@ 8%) = MM$ 1190

AVERAGE TRANSPORTATION COST PER BARREL = $ 2.77

affect the selection of a crude oil transportation system for Scenario 3. These factors are difficult, if not impossible to quantify and are described below.

a) Construction Time and Logistics

Construction time for each alternative is approximately four years. Therefore, there is no preference for a particular alternative on this basis.

For offshore terminal alternatives, most fabrication work is performed off-site and the minimal amount of on-site work required can be supported from the construction camp set up for drilling/production construction operations. Nearshore and transshipment terminal construction activities will probably require the establishment of a construction camp to support tank farm and long marine pipeline construction.

The construction of a land pipeline will also require a substantial support base.

St. George Island is inhabited but does not have sufficient infrastructure to support substantial construction operations.

b) Reliability

Tanker operations that require traveling through open water only, rather than through ice fields, are preferable because travel time is more predictable and the chance of getting stuck in unforeseen severe ice conditions is eliminated. Routine tanker operation through ice is unproven, but there is ample evidence that it is practical for this scenario. Considering this factor, Alternative 3A is preferable to the other four alternatives and there is virtually no difference among the four.

The risk of damage to a pipeline and consequent shutdown increases with its length. Considering only this factor, Alternatives 3D and 3E are the most preferable and Alternative 3A is the least.

For Scenario 3, both offshore terminals and nearshore terminals, except for Alternative 3A, require mooring and loading of tankers at a single point mooring in a location exposed to ice and waves. Ice conditions are approximately the same for the four alternatives.

Scenario 3 nearshore loading terminals do not require tankers to moor to a storage vessel. Therefore, alternatives that utilize a nearshore terminal instead of an offshore terminal will have a higher berth availability rate. However, this difference in berth availability has been taken into account in the determination of each element of the transportation system and all alternatives will have approximately the same reliability in this regard.

c) Environmental Considerations

From the point of view of minimizing disturbance of the environment, offshore storage is preferable to onshore storage. Onshore storage requires development of a large land area and the construction of a pipeline in a trench through the nearshore and surf zone. Operating personnel for offshore storage are quite isolated from existing communities Onshore storage requires a large amount of on-site construction personnel and equipment while most construction activities for offshore storage take place off-site. Considering these factors, Alternatives 3D and 3E are preferable to the other three alternatives.

The greater number of times the crude oil is loaded and unloaded en route to the refinery, the greater is the risk of a spill and subsequent damage to the environment, Therefore, alternatives that do not require a transshipment terminal (3A, 3C and 3E) are preferable to those that do (3B and 3D).

The construction of a land pipeline, with its access road would be quite disturbing to the environment and would probably encounter the most permit and regulatory difficulty. Considering this factor, Alternative 3A is undesirable compared with the other alternatives.

d) Other Considerations

In accordance with the terms of reference for this study, the alternatives that provide for offshore storage have been based on the assumption that. the crude oil storage structure will be separate from the drilling/production structure(s). However, the drilling/ production platforms for Scenario 3 are likely to be large gravity type concrete structures, similar to the North Sea Condeep structures, in which ample space for crude oil storage can be provided at relatively little additional cost. If this were done, the ATC of alternatives with offshore loading systems (Alternatives 3D and 3E) would be substantially reduced. Also, an offshore loading system without storage has a higher berth availability than one with a storage vessel.

No attempt has been made to optimize the location of the nearshore terminal for Alternative 3A. The site of the transshipment terminal, Balboa Bay, has been used. The ATC for all the alternatives, except Alternative 3A, is relatively unaffected by the location of the terminal. It is highly likely that a more suitable location for the terminal can be found, thus reducing the length of the pipeline required and consequently the cost. However, the ATC would not be reduced below that of Alternative 3E.

6.8 SENSITIVITY ANALYSIS

In order to evaluate the effect of variations in the scenario parameters on the conclusions regarding the optimum transportation alternative, a number of sensitivity analyses have been carried out. The parameter% varied for the analyses include:

- quantity of recoverable reserves (production rate),
- crude oil properties,
- distance to shore,
- water depth, and
- geotechnical conditions.

The effects of these variations on the individual transportation elements are discussed in the sections of this report in which the elements are described. This section is concerned with the effect on the overall transportation system alternatives for Scenario 3.

Appendix B contains tables which show the capital cost, annual operating cost and manpower required for each major transportation system element, for each alternative, and for each sensitivity parameter variation. The tables also list the present value of the total life cycle cost and the average transportation cost (ATC) of the crude oil for each case. They have been developed by fixing all scenario parameters but one at the base case values and setting the one parameter at a non-base case (sensitivity) value.

6.8.1 Recoverable Reserves

The base case recoverable reserves has been defined as 500 million barrels and the sensitivity values range from 100 million to two billion barrels. All size reservoirs have been assumed to perform in the same manner, as described in Section 3.3.2, with peak production rate equal to 9.1 percent of reserves.

Figure 6-14 presents the results of the recoverable reserves sensitivity analysis in the form of average crude oil transportation cost versus peak production rate. From the figure it is obvious that the transportation cost for each of the five alternatives considered is very sensitive to the production rate at rates below approximately 250,000 barrels per day. However, since the curves representing each alternative do not cross, the production rate does not affect the determination of the alternative that provides the lowest cost transportation system and Alternative 3E, offshore loading and direct shipment to the West Coast, is preferable on the basis of cost for all peak production rates considered.

6.8.2 Crude Oil Properties

The base case crude oil properties are quite suitable for transportation in either long pipelines or tankers. The sensitivity case crude oil has a relatively high pour point making pumping long distances under water impractical. For this type of crude, offshore

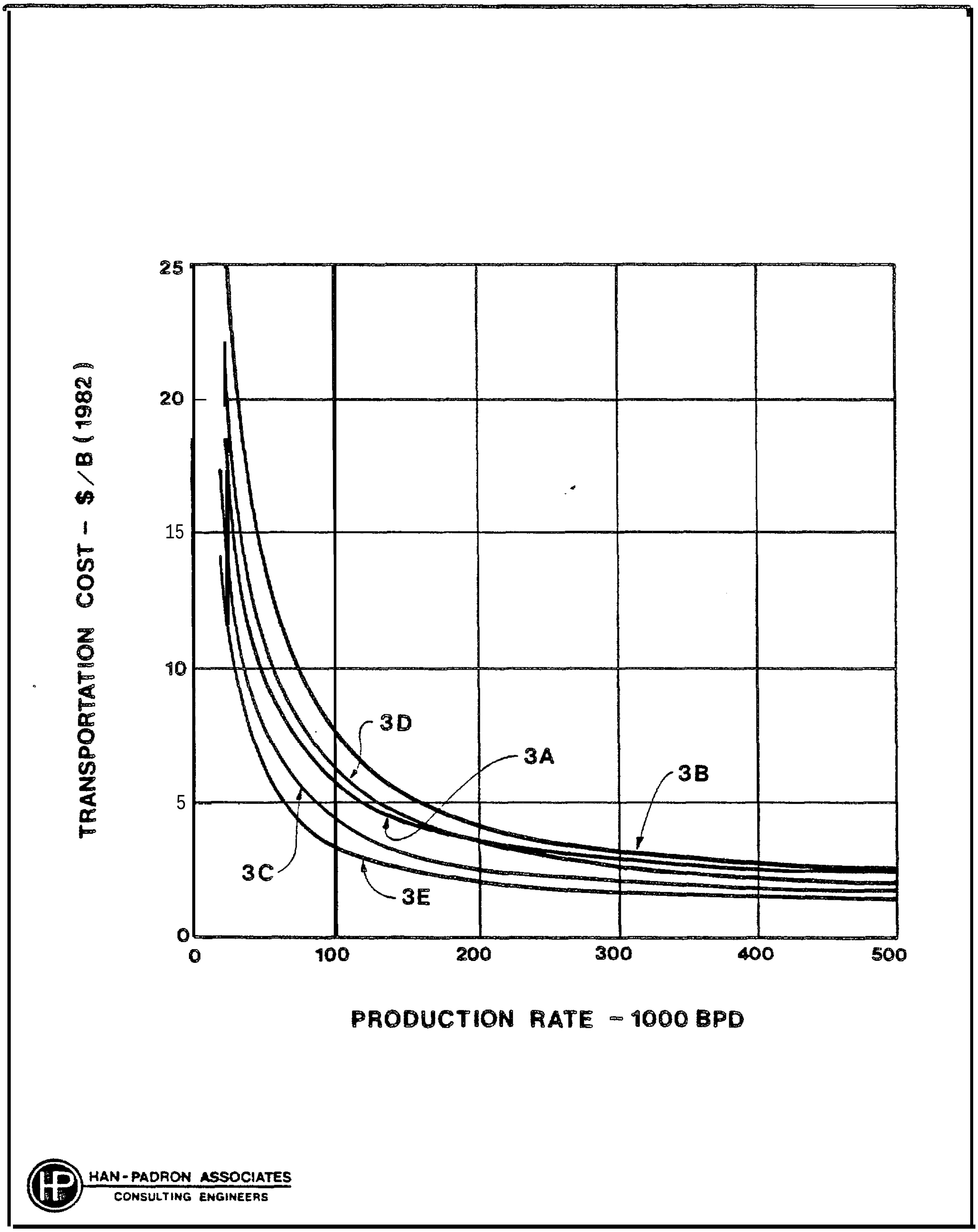

Figure 6-14. Scenario 3 crude oil transportation cost sensitivity to production rate.

loading alternatives are much more attractive than alternatives that require long pipelines.

The capital cost of all alternatives considered would be higher for the sensitivity case crude. For long pipeline cases the costs would become prohibitive and no further analysis was conducted. For offshore loading cases, loading pipeline diameters and pumping horsepower would increase but the increase in total transportation system cost would be negligible. Alternatives requiring trans-shipment of the crude oil would become very unattractive because of reduction in temperature of the crude that would result from the unloading and loading operations.

6.8.3 Distance to Shore

Variations in the distance of the production platform from shore have virtually no effect on Alternatives 3D and 3E which have offshore storage and loading. For Alternatives 3A, 3B and 3C, the variation in the average transportation cost from the base case to the maximum or minimum distance cases is between 6 and 12 percent and has no effect on the conclusions reached.

6.8.4 Water Depth

The average transportation cost for Alternatives 3A, 3B and 3C are not affected by variations in water depth at the production site because these alternatives do not include an offshore terminal. The ATC for Alternatives 3D and 3E are slightly sensitive to water depth within the range considered. The maximum variation in transportation cost is less than 1 percent and has no effect on the conclusions reached.

6.8.5 Geotechnical Conditions

As for water depth, variations of the seabed soil parameters affect only the offshore loading alternatives (3D and 3E). In both cases the poorer soil conditions of the sensitivity case have virtually no effect on the base case ATC.

6.9 CONCLUSIONS

On the basis of cost, transportation Alternative 3E, offshore storage and loading and direct shipment to the West Coast, is the most preferable. For the base case peak production rate, Alternative 3E has a 22 percent lower average transportation cost than the next most efficient alternative. Considering the other factors as described in Section 6.7.2, Alternative 3E is equal to or more preferable than the other alternatives in every case except that Alternative 3A has a higher reliability because the tankers are not required to travel through ice and the tanker mooring and loading system is a conventional system requiring no new development.

Incorporating offshore crude oil storage in the drilling/production platform will reduce the cost of Alternative 3E. Relocating the nearshore terminal may reduce the cost of Alternative 3A, but not below the cost of 3E. Considering the sensitivity analyses described in Section 6.8, Alternative 3E is the most preferable on the basis of crude oil properties.

Therefore, for the parameters as defined, Alternative 3E is the preferred method of transporting crude oil from the Southern Bering Sea.

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