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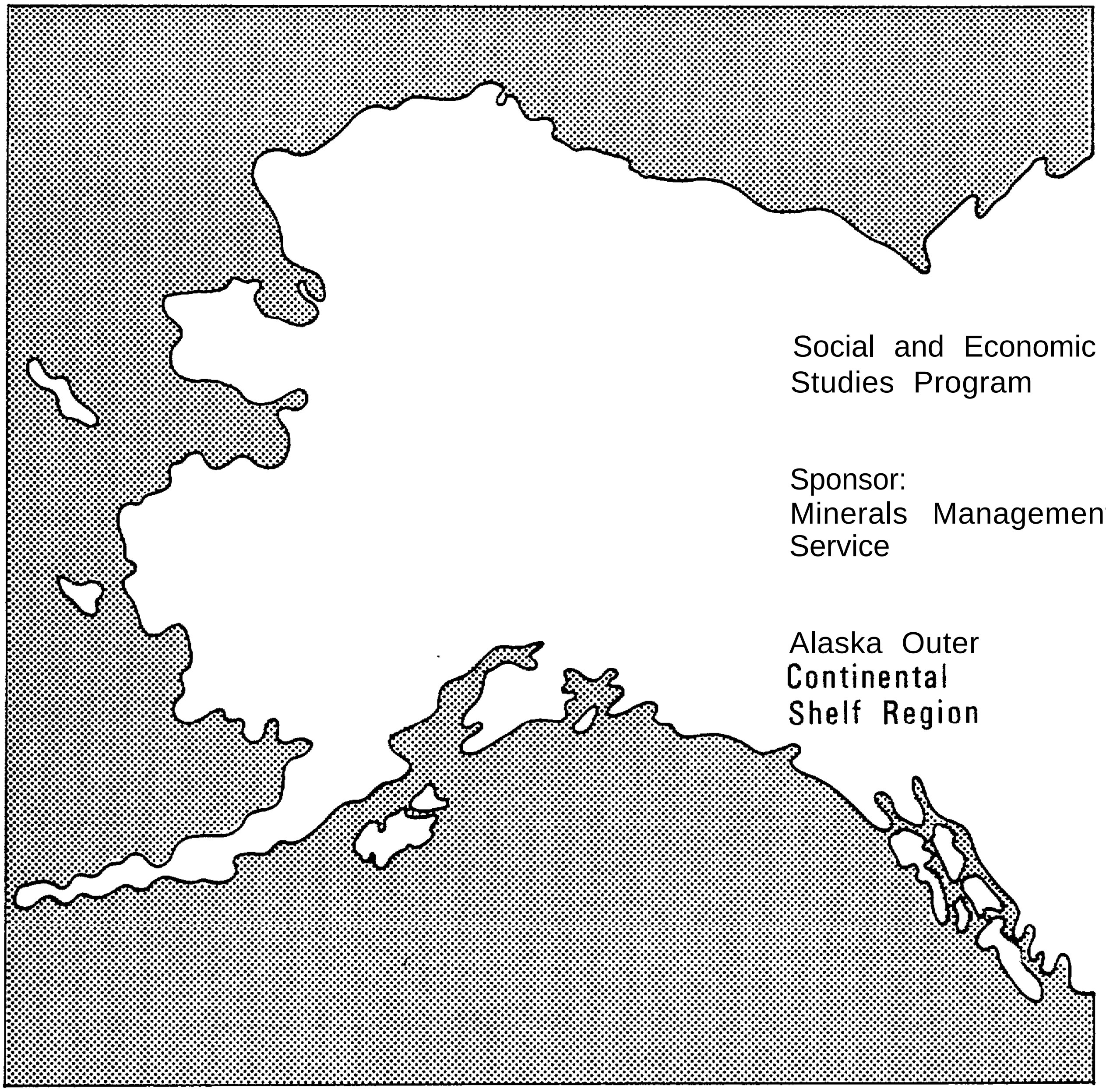
Technical Report
Number 109



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Alaska Outer Continental Shelf Region

Sub-Arctic Deep Water Petroleum Technology Assessment

TECHNICAL REPORT NO. 109

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SUB-ARTIC DEEP WATER
PETROLEUM TECHNOLOGY ASSESSMENT

Prepared for:

MINERALS MANAGEMENT SERVICE

ALASKA OUTER CONTINENTAL SHELF REGION

LEASING AND ENVIRONMENT OFFICE

SOCIAL AND ECONOMIC STUDIES UNIT

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NOTICE

The units presented in this report are metric with American equivalents except units used in standard petroleum practice. These include barrels (42 gallons, oil), cubic feet (gas), pipeline diameters (inches), well casing diameters (inches), and well spacing (acres).

SUB-ARCTIC DEEP WATER PETROLEUM
TECHNOLOGY ASSESSMENT

Prepared by:
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This report was prepared under the helpful guidance of Kevin Banks, Minerals Management Service.

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ABSTRACT

Sub-arctic deepwater regions in the Bering Sea and Gulf of Alaska possess the potential for hydrocarbon resources which will be explored in the near future. Exploration and development of these resources will entail considerable cost and activity.

Previous studies have generally addressed oil and gas resource development in areas where water depths were less than 200 meters (660 ft). These studies also anlayzed the economic and financial viewpoints, in addition to conducting technology assessments.

The primary purpose of this study is to review and assess the current technology and component costs feasible for exploration, production and transportation of oil resources in water depths beyond 200 meters in the study regions. An additional requirement for this study was to provide a basis for analyzing the economic and financial viewpoints. This basis is presented in a building block format which can be updated and refined as technology advancements are realized.

Within the current state of the art, costs for development beyond water depths of 1,000 meters (3,300 ft) should be considered somewhat academic for ice-free areas such as the Gulf of Alaska. Developments in the Bering Sea are feasible to about 300 meters (1 ,000 ft). In any event, the current costs to develop deepwater sub-arctic areas indicate a need for further technological development in terms of structural concepts. It could be concluded from this study that the conventional offshore methods of bringing wellheads to the surface is a luxury that requires further consideration. Supporting structure concepts based on floating vessels and tension leg platforms appear to be feasible in water depths approaching 1,000 meters.

Well productivity and the number of wells which can be accommodated in a given platform were a primary influence on the total production that could be achieved from a single platform. A self contained driling and production platform producing 100,000 BOPD was taken as the base case. Incremental production increases for a single platform were achieved through the addition of subsea wells to product 200,000 BOPD.

Exploration activities throughout the world have been performed in water depths over 2,000 meters (6, 600 ft). Technology is currently available to extend this horizon to over 3,000-meter (10,000 ft) water depths.

Infra-structure development was assumed to be pre-existing because of earlier nearshore developments presented in previous studies for the Bering Sea and Gulf of Alaska.

1.0 INTRODUCTION

1.1 Purpose

The principal purpose of this study is to identify the petroleum technology that may be used to develop offshore oil resources in the deepwater sub-arctic planning areas of the Navarin Basin, St. George Basin and Gulf of Alaska. This study focuses on the development of components to be utilized, including methods of exploration, production and transportation. A technical and economic assessment of these components, in conjunction with the relevant environmental and operational parameters, defines the feasible strategies that might be employed.

Previous studies performed for the Minerals Management Service have concentrated on the assessment of platforms, pipelines and terminals only for the shallower water depths of less than 200 meters. This study differs from those by providing a technology assessment with associated component costs and schedules for water depths beyond 200 mete rs.

1.2 Scope

This petroleum technology assessment is specifically directed to potential lease sale or planning areas in the Navarin Basin, St. George Basin and Gulf of Alaska beyond the 200 meter water depth contour. These planning areas are shown in Figure 1-1.

It should be emphasized that the technology assessment presented in this document was not influenced by specific estimates of recoverable reserves but was controlled by assumed well productivity and hydrocarbon characteristics from previous studies, and as directed and agreed with the Minerals Management Service. No attempt has been made to determine the economic feasibility of a potential development scenario for any of the planning areas.

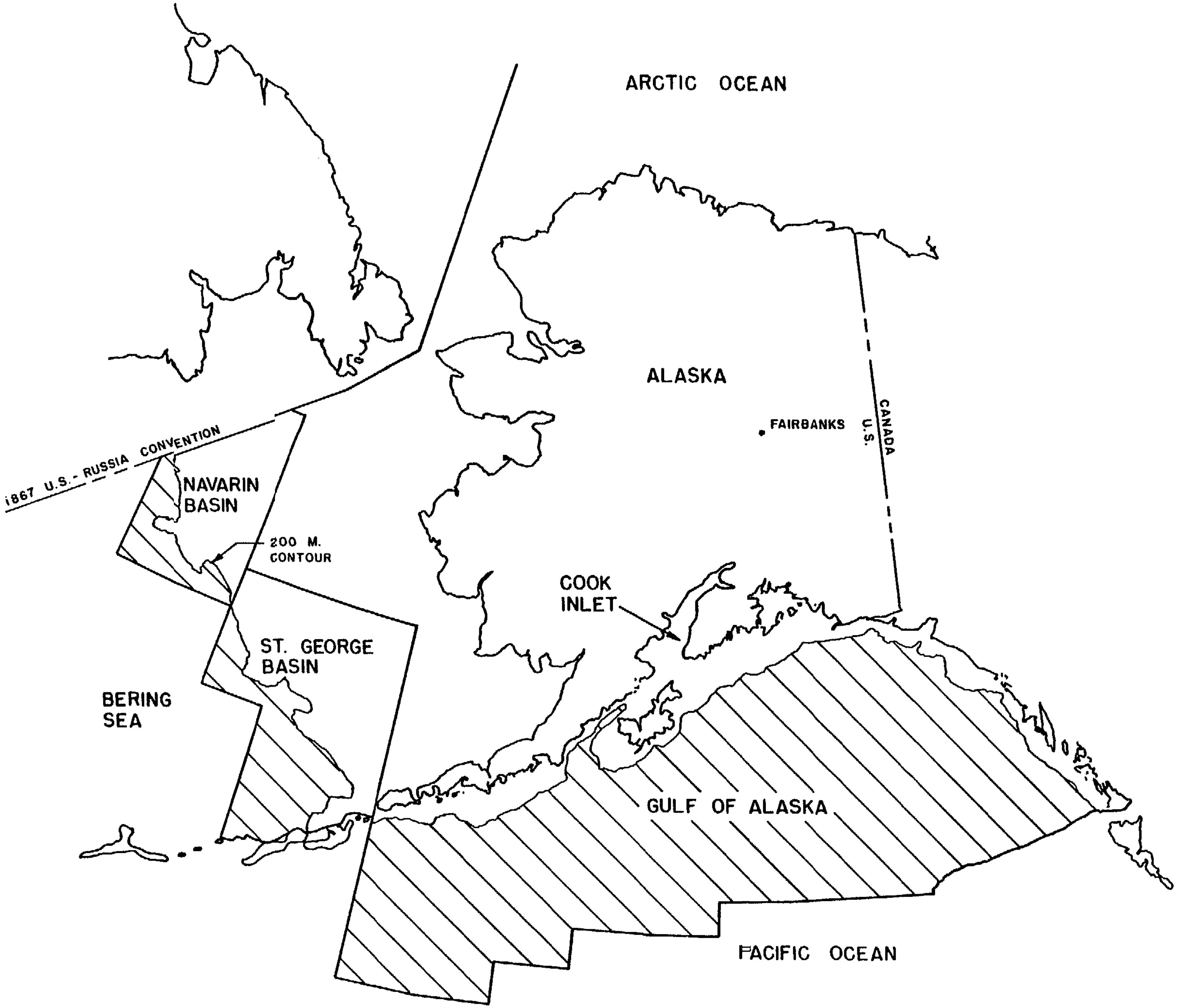

ARCTIC OCEAN
ALASKA
FAIRBANKS
CANADA
U.S.
1867 U.S. - RUSSIA CONVENTION
NAVARIN BASIN
200 M. CONTOUR
ST. GEORGE BASIN
BERING SEA
COOK INLET
GULF OF ALASKA
PACIFIC OCEAN

FIGURE 1-1

Previous studies have f ndicated minimum size production facilities that were considered feasible in nearby areas and this influence has been considered in this technology assessment. As petroleum assessment data becomes available and is applied to this study, certain assumptions and component costs may be subject to revision.

This study is directed toward "state of the art" components that, for the most part, have been proven viable. Even though the final details of the actual development scenario for a specific field may differ significantly from those proposed herein, the associated cost basis presented should still be representative.

The methodology for determination of evaluation factors is also provided to facilitate the multiple options that may arise in some circumstances. Further assistance in utilizing this "building block" approach is provided by a hypothetical development scenario in Section 2.0.

1.3 Study Boundaries

The study region encompasses those portions of the Navarin and St. George Basins in the Bering Sea and areas in the Gulf of Alaska which are in water depths greater than 200 meters. These areas are shown shaded in Figure 1-1.

Specifically, the Navarin Basin lies in the central Bering Sea and is bounded on the north by 63° N latitude, on the east by 174° W longitude, on the south by 58° N latitude, on the southwest by the 2400-meter isobath, and on the west by the U.S./Russia Convention Line of 1867 (Ref. 1). The 200-meter contour runs through the southwest sector of the basin.

The St. George Basin region lies in the southern Bering Sea. It is roughly a rectangular area extending from the Pribilof Islands of St. Paul and St. George southward to the Aleutian Islands along approximately 174° W meridian in the northern half of the region and the 171° W meridian in the southern half, thence northeastward along the Aleutian Island chain to Unimak Pass, and thence northward along approximately the 165" W meridian to about 57° N latitude. The 200-meter contour bisects the region from southeast to northwest.

The Gulf of Alaska region lies south of mainland Alaska in the extreme northeast corner of the Pacific Ocean. It covers a rather broad area extending from just south of Unimak Island near 165° W longitude east-northeastwards to the southeast Alaska Coast around Dixon Entrance near 136° W longitude. This region includes the Shumagin and Kodiak Basins as well as the Gulf of Alaska Basin itself. The 200-meter contour generally parallels the Alaskan coastline throughout this region, lying between 120 and 160 km (75 to 100 miles) off the southwest Alaskan Peninsula and between 80 and 120 km (50 to 75 miles) off the southeast Alaskan coast. There are, however, several tongues of deeper water which jut toward the coast including regions near the Shumagin Islands, in the Shelikof Strait, south of the Kenai Peninsula, and near Yakutat Bay.

1.4 Report Format

The report format employed in this study is to provide a "building block" approach to define the technically feasible components that could be economically utilized for field development scenarios in the three (3) study regions.

The "building block" approach presented in this study reflects the exploration, production and transportation components considered to be technically feasible for sub-arctic operations. The available systems or components were assessed by a consistent set of influencing factors that are expected to impact operations in the sub-arctic. From this technology assessment, a group of feasible technical components was derived. Estimated costs and schedules were developed for these components and presented in graphical form.

A concerted effort was made to link costs and schedules to credible data sources. In most cases, this effort was successful by utilizing data directly or by extrapolation using reasonable engineering judgment. However, the sub-arctic is considered to be a frontier area with the only offshore developments to date occurring in the relatively shallow waters of Cook Inlet. Initial extensions of production technology to deep water in other parts of the world have been clouded with a degree of uncertainty. Deep water developments in the study regions will have to contend with this factor as well as the unique sub-arctic environmental influences.

1.5 Reliability

The costs and schedules presented in this study were derived from data and experience in mature petroleum development areas. The use of such data in predicting costs for deep water sub-arctic development must be viewed with a degree of uncertainty. Even developments in the North Sea between the Norwegian and U.K. Sectors have experienced significant cost differentials for seemingly similar field production parameters.

The component costs in this technology assessment represent "the state of the art". These costs are intended to portray the anticipated costs or, at the very least, define the order of magnitude required for exploration and development. No attempt has been made to favor one particular component over another for any given function. The feasible technology is presented primarily as a basis for estimating time and costs. Unless otherwise noted, a contingency of 30%-50% should be added to total development cost for such operations as offshore drilling, construction activities, weather downtime and estimate uncertainties. No allowance has been included for any other factors such as pennit approvals and governmental regulations or potential time delays.

Semi-submersible exploratory drilling units and harsh environment construction equipment costs have been utilized in all planning regions to minimize weather downtime. However, site-specific parameters may indicate the economic use of less expensive, weather sensitive equipment. It was assummed that these factors would result in comparable final costs.

Onshore fabrication and material supply could be executed from the Far East or U.S. West Coast. Unit rates for support structures were derived from an average of the costs between these two areas. These costs are outlined in subsection 7.4. Thus, the costs presented may be on the conservative side (30% too high) for Far East supply while they might err to the low side (10% too low) for supply from the West Coast.

Fabrication and supply of topside production facilities were based on North Sea data from the U.K. Sector. This basis was utilized for previous estimates for Arctic production facilities and areassessment of these production costs indicates such data are within the realm of acceptable estimating accurracy. However, these costs may be somewhat conservative owing to government approaches to offshore development and increased productivity for the U.S. West Coast construction as compared to the U.K.

2.0 SUMMARY OF FINDINGS

2.1 Influencing Factors

The major influencing factors highlighted in this study can be catagorized under three (3) headings: physical environment, production characteristics and logistics. There are a number of important parameters within each of these categories, and an attempt has been made to assess the influence of each one.

2.1.1 Physical Environment

The sub-arctic is a harsh frontier environment in any case. But, for this study's regions of interest, developments for hydrocarbon production will also have to cope with the added considerations associated with deep water. Environmental factors primarily influence the selection of support structures for platform drilling and production facilities. However, the importance of personnel safety and productivity, drilling and production operations, exploration, and transportation are of equal standing. The influence of the physical environment is addressed in detail for each of the study regions in Sections 3.0, 4.0 and 5.0.

2.1.2 Production System Characteristics

The MMS has established that oil production facilities will be considered for this Technology Assessment (Ref. 20). Sufficient quantities of associated gas are assumed available to provide fuel for a self-contained offshore production facility. Excess quantities of gas will be reinfected. Production facilities are assumed to provide for water injection.

Production characteristics have been derived from previous work by the National Petroleum Council (NPC) in 1981 (Ref. 2) and agreed with the MMS for this study. Because of the costs associated with hydrocarbon production in severe, deep water environments, fields with a capability of producing less than 100,000 barrels of oil per day (BOPD), at the peak production rate, were considered uneconomic.

Because there is a strong indication that production facilities of 100,000 BOPD capacity may be uneconomic, all costs were calculated for 100,000 BOPD and 200,000 BOPD. Thus, one could extrapolate upward from this data, but the applications of deep water support structures is controlled by factors other than topsides weight as discussed further in this Section. Initial well production rate has been assummed as 4,000 BOPD. The ratio of producing wells to injection wells has been taken as 3:1.

Production has been idealized as three phase: oil, gas and water, with oil as the primary constituent. As noted above, associated gas will be of sufficient quantities to provide fuel with excess quantities to be reinfected. Produced water will be separated, cleaned and reinfected. Special production problems such as heavy crude or high pour point, sour gas (H_2S), CO_2 and oil/water emulsions have not been included. Reservoir pressure has been assumed sufficient to maintain designed production rates without pumping or other artificial lift methods. Reinfection of associated gas and water injection will be the only pressure maintenance required.

The three reservoir depths specified by MMS were 1,800, 3,700 and 5,500 meters (approximately 6,000 ft., 12,000 ft. and 18,000 ft.) below seabed. These depths were considered primarily for determination of drilling costs. Multi-zone completion wells were not included.

The number of wells that can be accommodated in a deep water platform are generally limited by structural capacity of the support structure. On the other hand, well productivity and reservior depth control the production rate that can be handled by a single platform. Production characteristics developed by NPC in 1981 (Ref. 2) indicated a maximum flow rate per well of 4,000 BOPD. This assumption has been adopted for this technology assessment to yield about 50 well slots (including producing and injection wells) On a deep water suPPort structure to produce about 100,000 BPD. Utilizing two (2) drill rigs per platform, all wells could be drilled in just over 4 years. This timing seems consistent with present industry practice toward meeting maximum production and utilizing injection to delay field production decline. It has been assumed that 50 well slots per platform is feasible for the 3,700 and 5,500 meter (approximately 12,000 ft. and 18,000 ft.) reservoir depths specified. Drilling costs for the 1,800 meter (approximately 6,000 ft.) reservoir depths are presented for information only, as current drilling technology, in terms of well spacing and directional drilling, could not effectively drain a shallow commercial reservoir from a single platform, regardless of the number of well slots and drilling rigs provided.

2.1.3 Logistics

The NPC study in 1981 (Ref. 2) showed that the industry recognizes logistic support for offshore operations as a great concern for basins in ice covered waters. While only the Navarin and St. George Basins off the West Coast of Alaska fall within regions which could experience ice, the remoteness of all three (3) study areas must be considered when planning offshore operations.

Experience gained from Cook Inlet and Prudhoe Bay developments, as well as the TAPS construction project, have shown that logistic support is within present technological capacities. The successful recent exploratory drilling operations in the Gulf of Alaska and in the Bering Sea were dependent in large part on logistical parameters. Existing ports along the Gulf of Alaska and in the

Aleutian Islands near St. George Basin coul d probably be expanded to handle offshore operations in those regions. However, for Navarin Basin, the lack of nearby onshore supply bases and the travel distances are of particular economic concern for the longer-tern production operations in this region. The specific requirements for each study area are outlined in Sections 3.0, 4.0 and 5.0.

2.2 Petroleum Technology Assessment

There exist many variations and alternatives on offshore systems that are technically feasible. The task of selection will be greatly influenced by reliability and economics. Major components of offshore development systems considered in this study were separated into categories as follows:

Exploration by semi-submersibles and drill ships,

Topside facilities with drilling and self-contained production capability for fixed and floating platforms,

Bottom founded drilling and production platform structures such as the conventional piled jacket, self-floater piled tower and guyed tower concepts,

Floating drilling and production tension leg platforms (TLP),

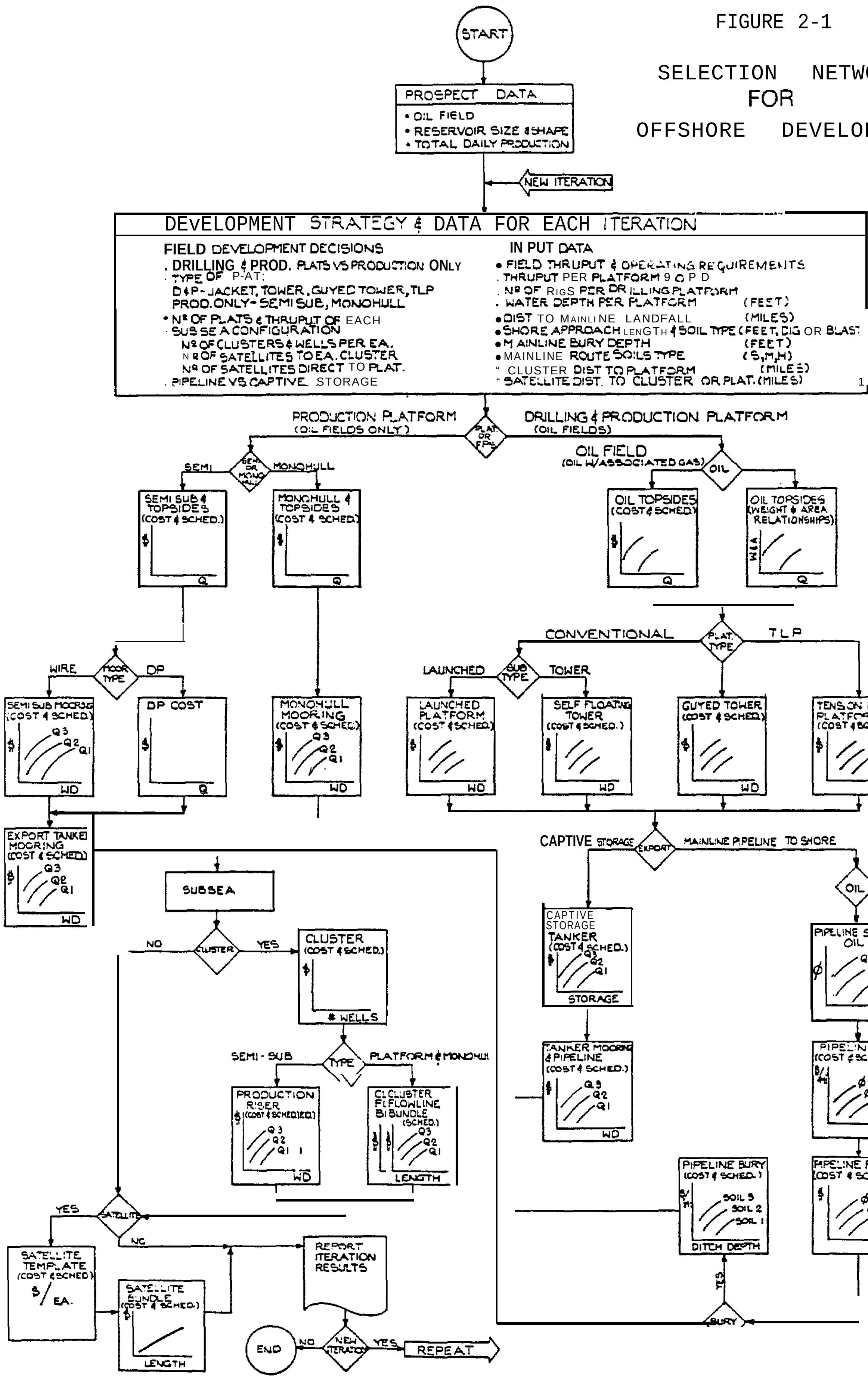
Floating production systems (FPS) based on semi-submersible and monohull configurations, and

Transportation systems based on pipelines and/or captive storage and offshore loading.

A network depicting the logical assembly of development scenario alternatives is shown in Figure 2-1. The cost and schedule data summary for each region is presented in this section. Detailed

FIGURE 2-1

SELECTION NETWORK
FOR
OFFSHORE DEVELOPMENT



technology assessment is presented for each region in Sections 3.0, 4.0 and 5.0. Cost and schedule development is presented in Sections 6.0 through 9.0.

The impact of influencing factors on various system components is presented in matrix form in Figure 2-2. The relative influence rating is as follows:

3 = major technical and cost influence
2 = moderate technical influence with minor cost impact
1 = minor technical influence with negligible cost impact
0 = negligible technical influence
- = the factor is not applicable to the system of interest

As would be expected, those parameters characterizing thruput, water depth and distance to shore typically exert the major influences.

Drilling technology has progressed to the point where the water depth record is on the order of thousands of feet. Although various operating companies have tested deep water production systems in moderate depths on a research basis, more long-term experience with oil and gas production in controlled environments is "needed before production technology can be said to be demonstrated on a routine operational basis in the water depths contemplated in this study.

It appears defensible to speculate that development operations are technically feasible today in over 900 meters (approximately 3,000 ft.) of water in the ice-free areas and up to 300 meters (approximately 1,000 ft.) in the Bering Sea, where sea-ice is expected. Additional technological advancements are to be expected; however, forecasting that impact of water depth limits appears unrealistic in light of the lack of deepwater experience in other mature producing regions.

SYSTEM COMPONENT \ COST INFLUENCE	THRUPUT	DAYS OF STORAGE	NO. OF RIGS	NO. OF WELLS	DK OUTLINE AREA	PAYLOAD	WATER DEPTH	PIPELINE LENGTH	OIL TYPE	LAUNCH BARGE	SEA ICE
TOPSIDES (HIDECK)	3	-	3	1	1	1	0	1	-	2	0
LAUNCHED JACKET	2		3	2	3	1	3		1	3	1
SELF FLOATING TOWER	2		3	2	3	1	3		1		1
GUYED TOWER	2		2	2	1	1	3		1	3	2
TLP	3		3	2	2	3	3		1	0	3
CAPTIVE STORAGE	3	3				0	1	0	-		1
TANKER MOORING	3	3				0	3	2	1		3
MAINLINE TO SHORE	3			1			2	3	1	-	0
PIPELINE BURIAL	1						2	3	3		
PIPELINE RISER	3			1			3	0	0		1
SEMI-SUB FPS	3	3		2	2	2	1	1	0		1
SEMI-SUB MOORING	3	3		0		1	3	1	1		3
PRODUCTION RISER	3		0	3			3	0	-		3
MONOHULL FPS	3	3		1	1	1	1	1	0		1
MONOHULL MOORING	3	3		1		0	3	2	1		3
SUB SEA CLUSTER (UMC)	1			3			1		1	1	
PRODUCTION FLOWLINES	3	-		1			1	2	1		0

FIGURE 2-2 DEVELOPMENT SYSTEMS INFLUENCE MATRIX
(See text for legend of influence ratings)

Single-piece conventional bottom-supported platforms are feasible in 300-450 meters (1,000-1,500 ft.) water depths. Single-piece guyed towers are believed to be feasible up to 600 meters (approximately 2,000 ft.) water depth. TLP's appear to be one of the few self-contained drilling and production platform concepts feasible beyond 600 meters (approximately 2,000 ft.); however, their forecasted costs are very high.

Conventionally moored (as well as dynamically positioned) floating drilling and production platforms could not be properly addressed within the study budget because of the significant amount of original work such systems demand. Their exclusion from this broadcompilation of offshore development systems leaves a regrettable deficiency in a frontier deepwater arena fertile for imaginative options. Likewise, multi-piece jacket and guyed tower possibilities could not be pursued.

Purpose-built floating production platforms (FPS) with 10 days of oil storage appear feasible even for production rates of 200,000 BPD. Production risers and tanker moorings with multi-function flowline requirements are ready for water depths over 300 meters (approximately 1,000 ft.) and have been conceptualized for up to 1,800 meters {approximately 6,000 ft.) water depths. Development and prototype tests are underway.

Pipeline technology is ready for water depths beyond 900 meters (approximately 3,000 ft.). Equipment and existing practice can be modified to fulfill specific deepwater project requirements. The technology and equipment required to bury submarine pipelines more than 4.5 meters (approximately 15 ft.) below the mudline is not ready today, although much research and development work is focused on trenching systems. However, this item is related more toward shallow water, shorefast ice hazards and shore approach areas rather than being a requirement for the deepwater regions in this study.

Pipeline repair operations are presently limited by diver assist capabilities - to 450 meters (approximately 1,500 ft.). Damaged lines in deepwater areas will require relaying of a segment.

2.3 Development Costs

The summary costs presented in this section reflect the current state-of-the-art concepts and costs extrapolated to deepwater sub-arctic areas.

An overall project spending forecast may be developed from the capital cost buildup versus project duration curve shown in Figure 2-3. This curve is representative of a broad cross-section of topsides and platform projects where the durations of the individual components are relatively similar. A typical schedule for the development of a 500,000-BOPD system project is shown in Figure 2-4.

General contingency allowances have not been added to the somewhat speculative costs provided herein. Where considered appropriate, such as for topsides equipment prices and weather delays associated with continuous marine operations like pipeline installation, relative contingencies have been incorporated.

In recognition that rough weather is to be expected year-round in the Alaskan offshore, the use of less weather-sensitive semi-submersible construction vessels is assumed. The more expensive rates for this equipment should provide an ample cost forecast to accommodate alternative approaches using less expensive marine spreads subject to greater weather delays.

Allowances have been added to all cost estimates to cover project management, design, inspection, certification and constriction insurance. These cost components have been broadly categorized as Project Management, Design and Certification & Construction Insurance.

FIGURE 2-3

TYPICAL OFFSHORE PROJECT

CAPITAL SPENDING BUILDUP

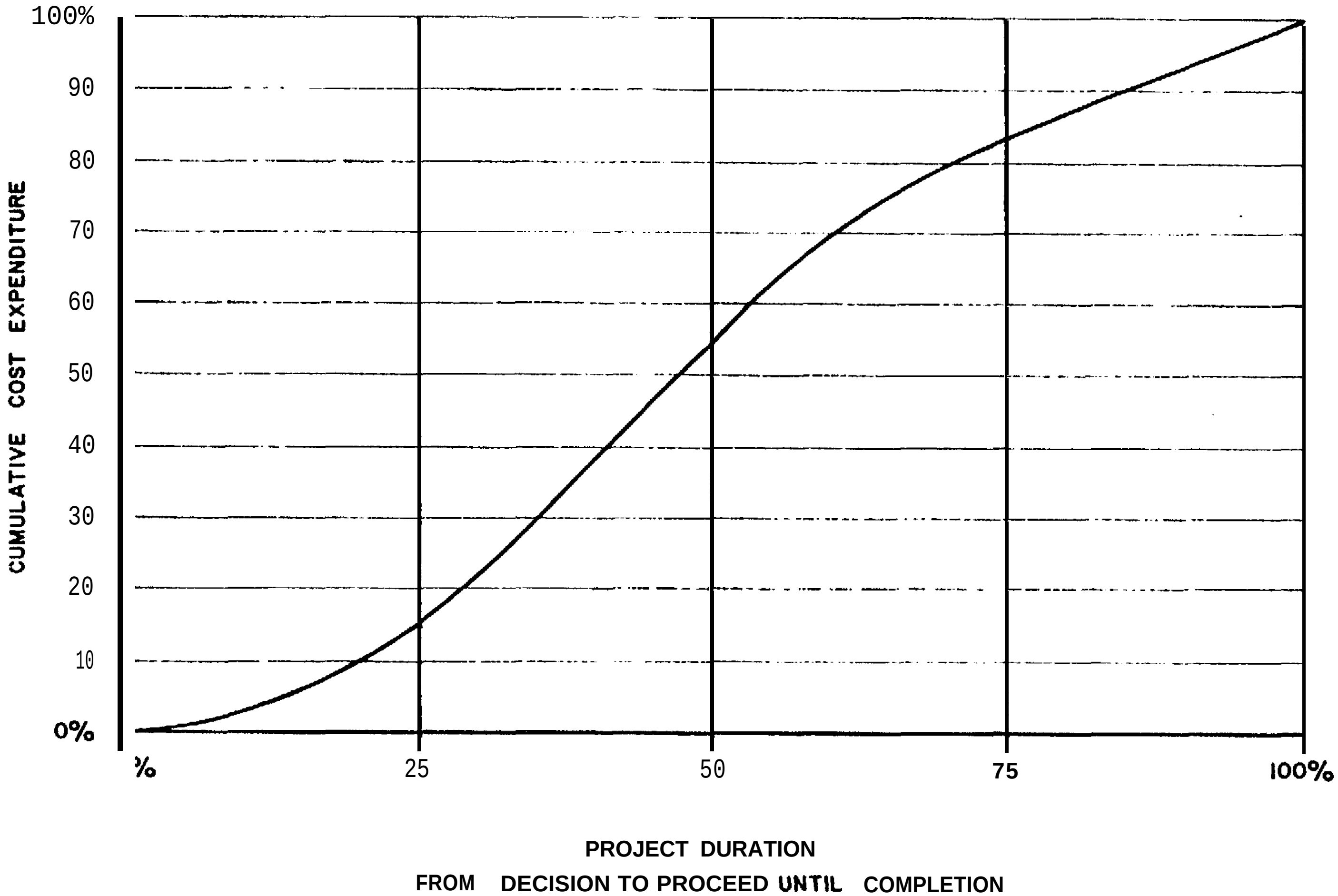
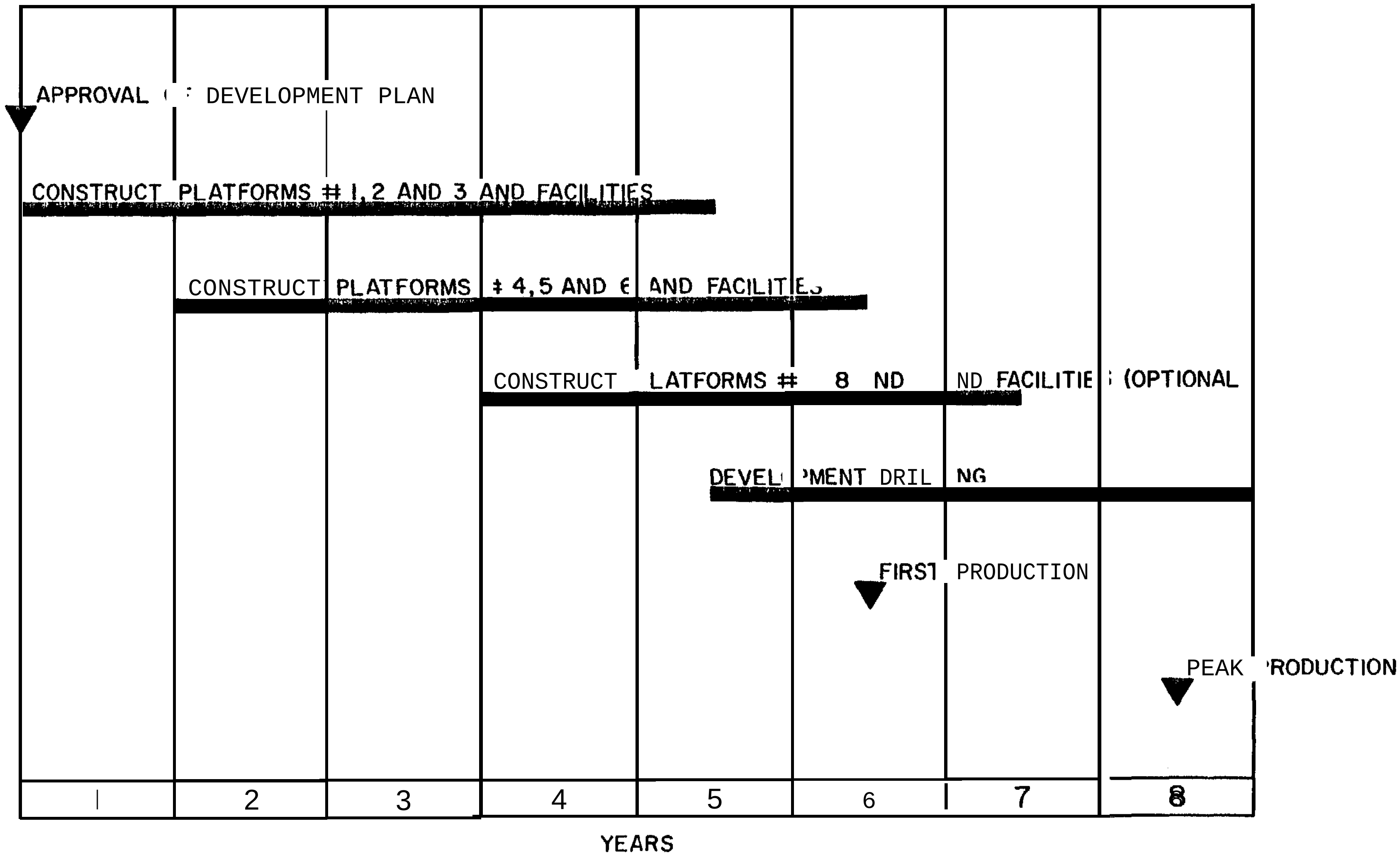


FIGURE 2-4

DEVELOPMENT SCHEDULE

OIL CASE - 500.000 BARRELS PER DAY MAX.



The allowance for each category is varied to reflect the unique requirements of each development system and are applied to each system and/or component as a percentage of its installed cost. Examples of the allowances used are shown in Table 2-1.

TABLE 2-1

System/Components	Management	Design	cost
Topsides	15.0%	7.5%	5.0%
Jackets, Towers & Guyed Towers	8.0%	4.5%	5.0%
Pipelines	5.0%	1.5%	5.0%

2.3.1 Drilling Costs

In accordance with MMS instructions, drilling costs were developed for three (3) reservoir depths: 1,800; 3,700; and 5,500 meters (6,000; 12,000; and 18,000 ft, respectively). For each study area these costs were broken into categories to cover exploratory wells drilled by floating vessel, development wells drilled from a fixed platform, and subsea development wells drilled by floating vessels. The anticipated 1983 costs are presented in Table 2-2 from the data presented in Section 6.0.

TABLE 2-2

EXPLORATORY & DEVELOPMENT WELL COST SUMMARY

(FIGURES IN 1983 $ MILLIONS)

	GULF OF ALASKA			ST. GEORGE BASIN			NAVARIN BASIN		
Well Depth Below Seabed: (m)	1800	3700	5500	1800	3700	5500	1800	3700	5500
(ft)	6000	12000	18000	6000	12000	18000	6000	12000	18000
TYPE OF WELL									
EXPLORATORY	11.0	21.0	43.0	13.0	24.0	53.0	16.0	30.0	66.0
PLATFORM DEVELOPMENT	4.0	7.0	11.0	5.0	8.0	12.0	5.o	9.0	14.0
SUBSEA DEVELOPMENT	16.0	28.0	50.0	18.0	31.0	58.0	18.5	34.5	70.0

2.3.2 Platform Costs

Platform costs are composed of costs for production facilities and support structure. Section 8.0 outlines the production facilities costs for oil production rates of 100,000 BOD and 200,000 BOD. The total installed costs were consistent in all study regions with the apparent differences beyond the accuracy of estimating methods.

Support structure costs were sensitive to region, production rate and water depth. The primary differences between the regions focused on seismic activity and sea ice considerations. Unstable, sloping seabed conditions were an important influence that was common to all regions. The total installed cost of platforms, including production facilities and support structure is summarized in Figure 2-5. Floating Production Systems (FPS) exhibit an advantage over the bottom founded guyed tower and TLP in water depths beyond 300 meters (approximately 1,000 ft.) However, the subsea drilling costs associated with the FPS negate this advantage.

Annual production operating costs were derived from the NPC Study (Ref. 2) as shown in Figure 2-6 for 1981. The lower part of the curve represents the Gulf of Alaska, while the upper band is expected for Navarin Basin with St. George assuming an upper median value. It is assumed these costs are realistic for 1983 and include:

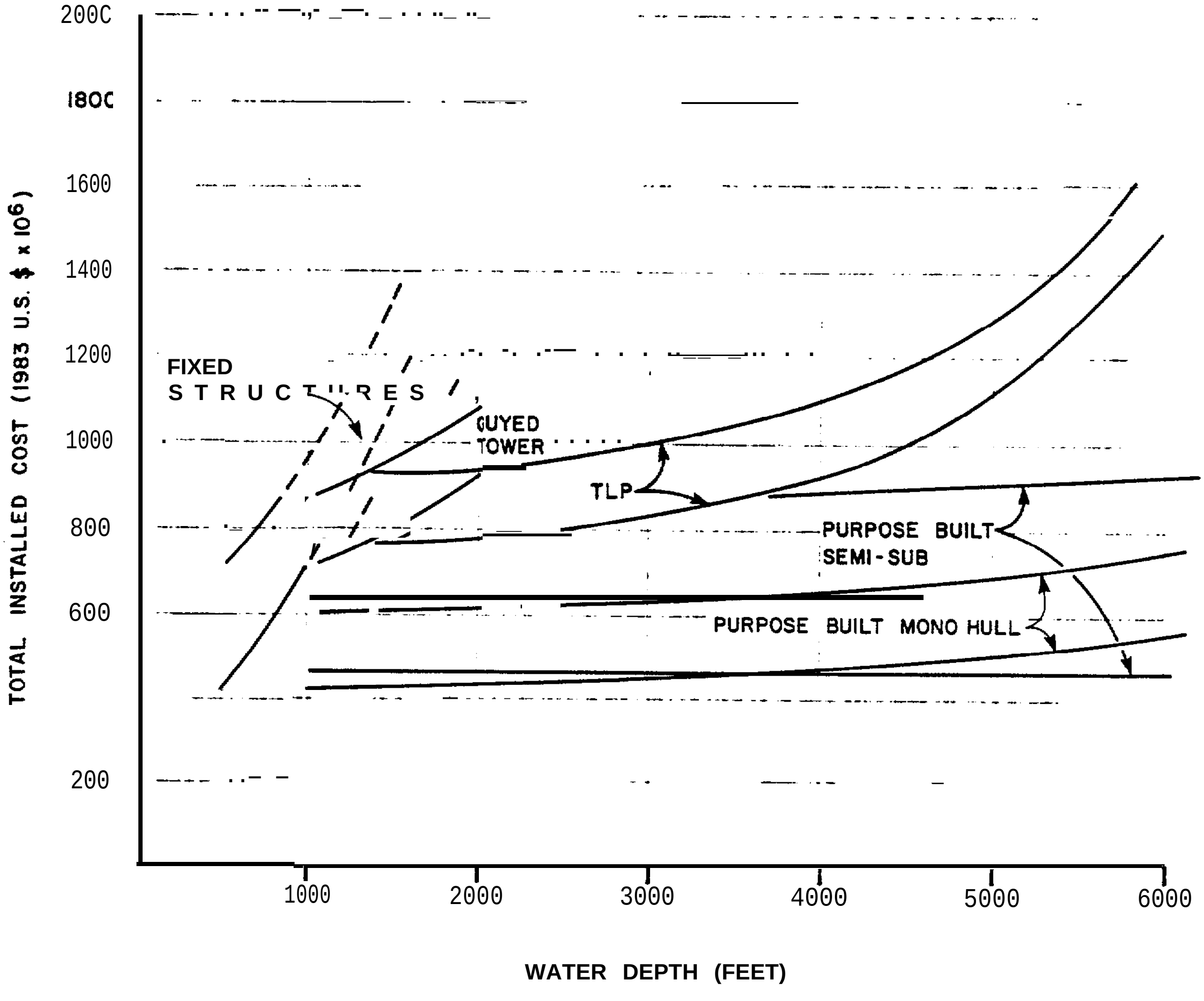
- Labor, supervision, overhead and administrative costs
- Communications, safety and catering
- Supplies and consumables
- Routine maintenance
- Well service and workover
- Insurance
- Transportation of personnel and supplies.

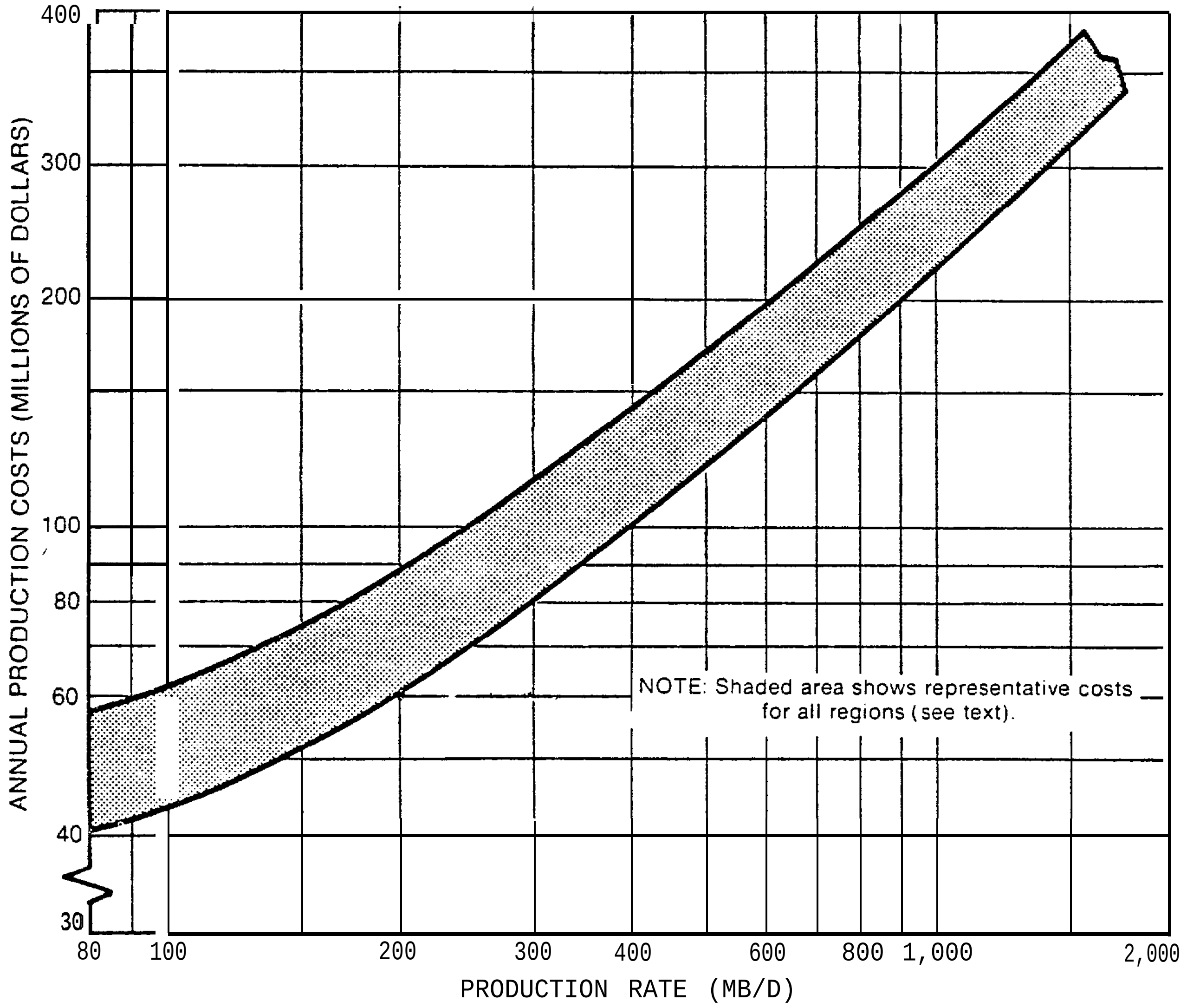
FIGURE 2-5

DEVELOPMENT PLATFORM COST

ALL REGIONS

COSTS INCLUDE:	**PRODUCTION FACILITIES**
	SUPPORT STRUCTURE
	ENGR., FABR. & INSTALLATION
COSTS EXCLUDE:	**DRILLING**
	EXPORT SYSTEM
	OPERATING EXPENSE





ANNUAL PRODUCTION COSTS VS. PRODUCTION RATE

FIGURE 2-6

(Source: NPC Study Reference 2.)

2.3.3 Transportation

Transportation costs are controlled primarily by distance to the nearest onshore terminal. Pipeline costs were in excess of $2.5 million per mile in the study regions. It was assumed that long pipelines in excess of 320 km (approximately 200 miles) would require intermediate pumping platforms, resulting in a factor of about 2.0 for pipeline costs. However, there is a specific study in progress for the MMS that provides greater insight to this point.

Pipelines were considered viable for the Gulf of Alaska; only marginal for remote parts of the St. George Basin; and uneconomic for the Navarin Basin.

Offshore storage and loading was considered as the economically viable scheme for Navarin and might be the initial concept for St. George Basin. Transportation costs summarized in Table 2-3 present the anticipated costs.

TABLE 2-3

TRANSPORTATION COST SUMMARY

(200,000 BOPD: Costs in 1983 $ Millions)

MARINE PIPELINES	GULF F ALASKA*	ST. GEORGE **	NAVARIN
Cost PerKilometer/Mile	1.9/3.0	3.17/5.1	
Length Kilometer/Miles	(240/1 50)	(322/200)	
Total Capital Cost	450	1,020	
Operating Cost Per Yea r	4.5	21.0	
CAPTIVE STORAGE			
Storage Vessel			
300 m/1,000 ft water depth -		80	80
900 m/3,000 ft water depth -		113	113
Shuttle Tankers (3)		100	110
Operating Costs		30.	32.

* Gulf of Alaska pipeline costs include burial of the line throughout its entire length. If burial is not required or desired, the cost per mile and total capital cost would be significantly reduced.

** Source: NPC Study Reference 2

3.0 PETROLEUM TECHNOLOGY ASSESSMENT RESULTS - GULF OF ALASKA

3.1 Influencing Factors

The Gulf of Alaska has the more developed infrastructure of the three study regions. However, this area exhibits the most severe wave and seismic requirements.

3.1.1 Environment

The Gulf of Alaska is located at the end of the longest overwater storm track in the world. The low pressure systems which develop in the western North Pacific move along a northeast to east track and encounter no obstruction to this movement until they reach the Gulf of Alaska. Consequently, the fetch for storm winds can exceed 1,850 km (approximately 1,000 nautical miles) thereby causing some of the worlds most severe sea conditions (Ref. 15). In addition, fatigue considerations in the Gulf of Alaska will probably be more severe than in the other two basins. There is a 25% probability that wave heights will exceed 2.5 meters (approximately 8 ft.) in all 12 months of the year which gives rise to fatigue requirements comparable to the North Sea.

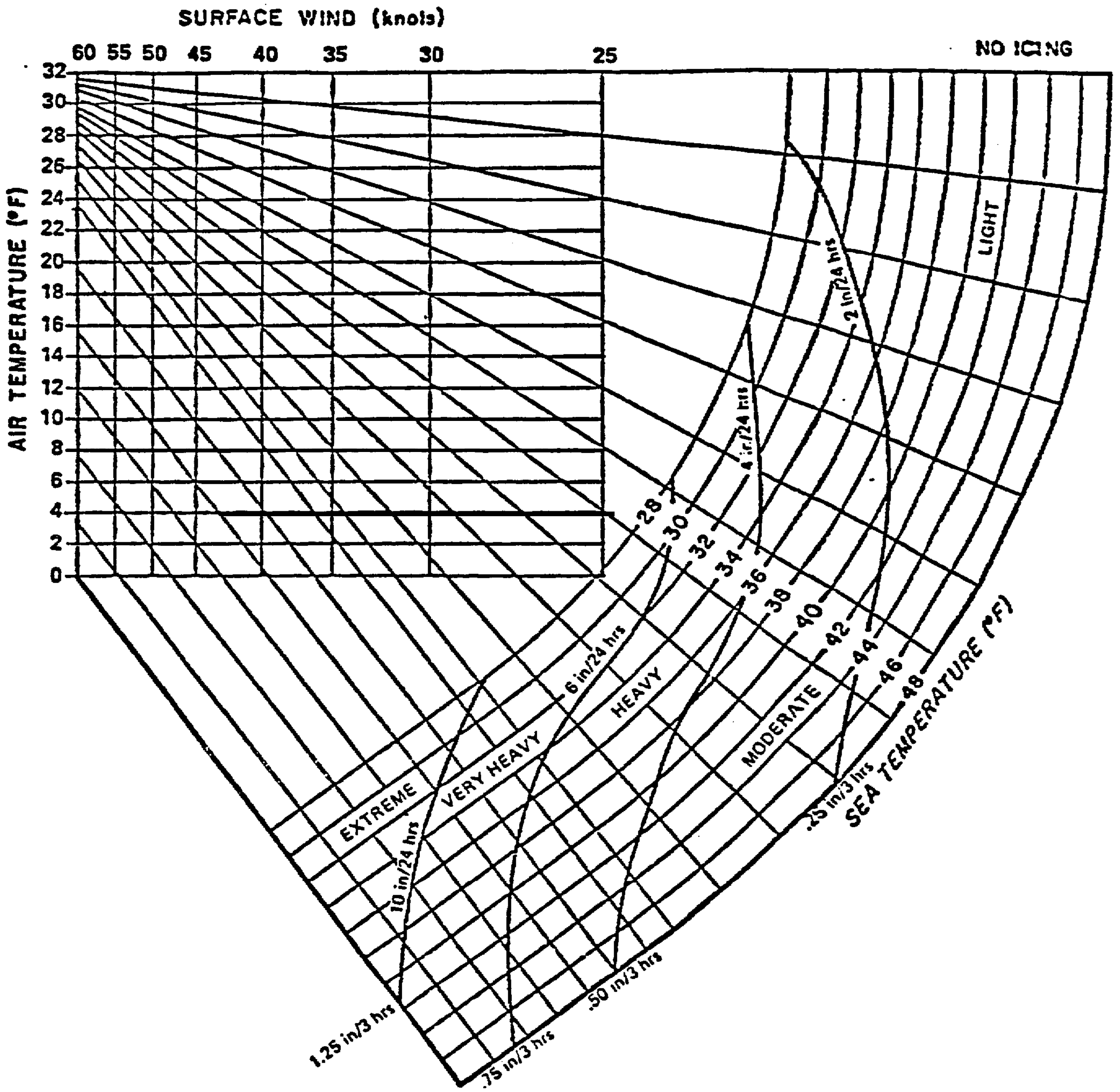
Sea ice will not be a consideration here because the prevailing winds and currents tend to keep the few ice pieces that do float out of coastal lagoons and rivers near to the shore (Ref. 15). However, ice accretion on the superstructure will be a design consideration because the combination of wind speed and air and water temperatures, which are conducive to such icing, do occur during the winter months.

Superstructure icing in a marine environment can be a serious hazard to navigation and other offshore activities in any region where freezing air temperatures exist over the sea. In particular, ship icing has long been recognized as a major problem (Ref. 32).

Icing on marine structures can be caused by two sources: sea spray (spray or superstructure icing) and/or atmospheric fresh water from atmospheric phenomena such as freezing rain, ice fog, etc. (atmospheric icing) - Refs. 7, 8 and 9. . Sea spray is, by far, the major source of ship icing. According to one study which analyzed reports from more than 2000 ships worldwide, ocean spray alone caused ship icing in 89.8% of all cases (Ref. 32).

Nomograms have been developed to predict levels of superstructure icing based on air temperature, sea temperature, and surface wind speed. One nomogram that has been recommended for use in the Gulf of Alaska and eastern Bering Sea is given in Figure 3-1. Based on a limited amount of ship data, Wise and Comisky have developed a map showing zones of icing categories in these same regions as shown in Figure 3-2 (Ref. 31). Much of the deep water portions of the Gulf of Alaska appear to lie in the heavy to extreme superstructure icing zones. The design level of icing that might accrete on the topside decks of exploration and production systems should be significantly less since spray icing is not expected to reach the higher deck elevations of such structures. Instead, atmospheric icing will be the major source of ice accretion on the decks of these structures. The present limited data base indicates that atmospheric icing will be of less magnitude and frequency than spray icing. Design ice thicknesses equivalent to those for moderate spray icing (4 inches) have been mentioned in the industry for application to fixed production structures in Navarin Basin. Based on this number, ice collecting on exposed facilities would amount to a total deck load increase of around 5%, a manageable load increase.

The continental slope in the eastern Gulf is relatively smooth and steep while in the western Gulf it is much more irregular due to the proximity of the Aleutian Trench. Much of the continental shelf in this region is mantled with a veneer of unconsolidated sediments. However, a profile of the sediments has not been evaluated as yet. Due to the steepness of the continental slope and the potential for



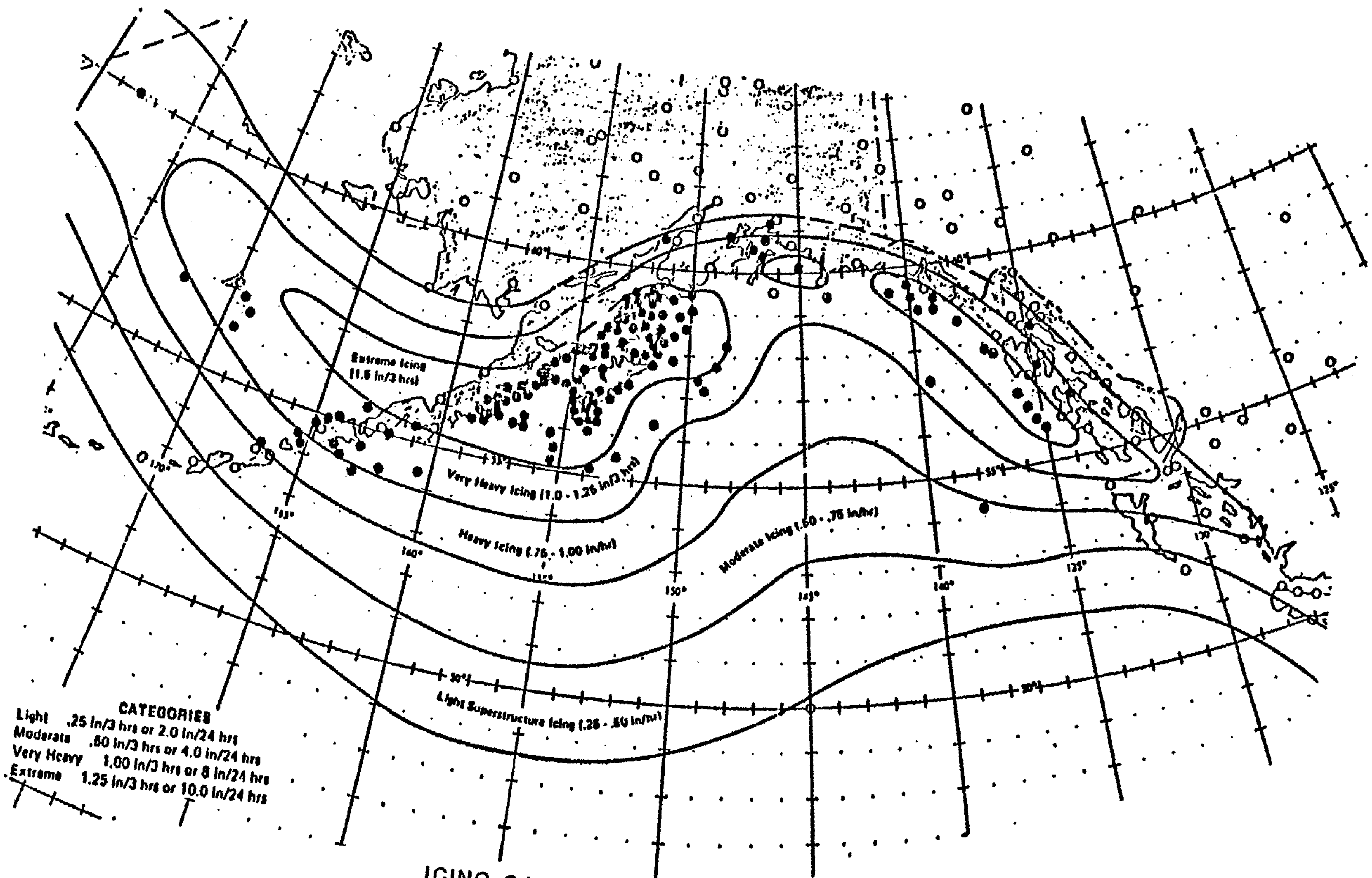
CATEGORIES

NAME	RATE PER 3 HOURS
light	.1″ 10 25″
Moderate	.25″ to .50″
Heavy	.50″ to .75″
Very Heavy	.75″ to 1.25
Extreme	1.25+″

NOMOGRAM FOR

GULF OF ALASKA AND EASTERN BERING SEA

FIGURE 3-1



ICING CATEGORIES MAP

FIGURE 3-2

(Isolines indicate estimated zones of icing categories with the most extreme conditions. Black dots indicate known locations of icing events from January 1976 through January 1980.)

weak, unconsolidated soils, submarine slides and slumps as well as liquefaction during seismic excitation must be considered in the deep water areas under investigation in this study.

The entire Gulf of Alaska study area is in a high seismic risk zone. API classifies parts of the region as Zone 4 (peak horizontal ground acceleration = 0.25 g) and parts as Zone 5 (peak horizontal ground acceleration = 0.40 g). Earthquakes with magnitudes greater than 8.0 on the Richter Scale can be expected to occur in the region approximately once every 20 - 25 years (Ref. 15). Such earthquakes will be a major design consideration for bottom-founded systems. They will also be a consideration for floating systems (and their risers as well) due to possible amplification of vertical vibrations through the water column under the surface vessel. Besides direct seismic vibration, submarine landslides and liquefaction of sediments triggered by the earthquake could cause significant damage to platforms, wells, and pipelines. Tsunamis could cause significant damage to onshore terminals and support facilities that serve Gulf of Alaska projects, but this should not have a significant effect on the offshore structures themselves since they will be located well out to sea.

A summary of environmental characteristics for this region is presented in Table 3-1.

3.1.2 Logistics

The Gulf of Alaska has perhaps the more highly developed infrastructure support potential of the three basins. In other words, it is the least remote because there are several communities that could act as support/supply bases within about 100 to 150 miles of most of the study region. References 15, 16, 17, 18, and 19 provide the basis of infrastructure support assumptions. Potential support and supply facilities include Yakutat, Yakataga, Middleton Island, Cordova, Seward, Anchorage, Kenai, and Valdez.

TABLE 3-1

BENCHMARK ENVIRONMENTAL PARAMETERS
GULF OF ALASKA

ENVIRONMENTAL PARAMETER	DESCRIPTION
Sea Ice	None
Superstructure Ice Accretion	Assume Design Thickness for "Stationary" structures = 10 cm (4 in)
Ambient Temperatures	Extreme Air = -12°C To +16°C Extreme Water = 3.5°C To +14°C
Wind Speed (l-minute average)	10yr = 150 km/h (95 mi/h) 100 yr = 200 km/h (125 mi/h)
Wave Height & Period (1 0-year return)	Max. = 30m; 17 Sec Period Sig. = 17 m; 13 Sec Period
Current	AVG Surface Current = 1 knot Storm Current = 3 knots
Tide	3 m (10 ft) Based on the Higher High Water Tides at N. Gulf Coastal Locations
Seafloor Profile	Steep gradients, ranging from just over 2° off Kenai Peninsula to near 7° in vicinity of Yakutat
Geotechnical Considerations	Slope sediments appear to be clayey silt with instability potential; liquefaction possible under seismic excitation
Seismicity	Both API Seismic Zones 4 and 5 occur; Zone 4 = 0.25 g Horiz. Ground Acceleration Zone 5 = 0.40 g Horiz. Ground Acceleration

3.2 Exploration Systems

Exploration systems in the Gulf of Alaska deep waters have been developed from the North Sea harsh environment experience with floating drill rigs, such as semi-submersibles and drillships. This new generation of drilling rigs are rated to operate in water depths to 3,050 meters (10,000 ft.) and drill to depths of 9,100 meters (30,000 ft.).

These units feature enclosed and heated work areas to provide a more productive work environment, freeze protection, designs to inhibit superstructure icing, large storage capacity and a higher degree of stability to overcome the harsh weather.

3.3. Production System Components

The production system components consist of the production facilities, support structure and transportation system. Production systems in the Gulf of Alaska are expected to resemble those currently utilized or envisaged for North Sea deep water areas. These systems will be influenced by the effects of lower well productivity, seismic activity and the extent and size of commercially viable developments. Of the three (3) study regions, the Gulf of Alaska appears to be the more promising region in terms of infrastructure development, proximity to shore and environmental requirements. For these regions development costs are lowest in this region.

3.4 Typical Production Scenario

A typical production scenario for the Gulf of Alaska is shown in Table 3-2. The potential field will be produced from two (2) production platforms. Production is transported by pipeline to an existing onshore terminal for export.

TABLE 3-2

TYPICAL PRODUCTION SCENARIO

GULF OF ALASKA

Exploratory Wells:	6
Reservoir Depth:	3,700 meters (12,000 ft.)
Production Rate:	200,000 BOPD
Water Depth:	300 Meters (1, 000 feet)
Distance From Landfall:	240 Km (150 miles)
No. of Platforms:	Two
No. of Platform Wells:	100 (incl. producing & injection)
Pipelines:	To onshore terminal

3.5 Cost Estimates

Estimated costs for the typical production scenario presented in Section 3.4 are summarized in Table 3-3. The cost basis is derived from the cost details in Section 6.0, 7.0, 8.0 and 9.0. Production platform costs are shown in Figure 3-3. These results indicate two 100,000 BPD production platforms may be more cost-effective as opposed to a single platform with subsea wells when one considers the high costs of drilling subsea wells and the installed costs for a subsea manifold system and associated pipelines. Offshore loading and storage may also be a viable and economic alternate to constructing an offshore terminal and pipeline to shore. However, this would be influenced greatly by the amount of development in this overall area.

TABLE 3-3

PRODUCTION SCENARIO COSTS

GULF OF ALASKA

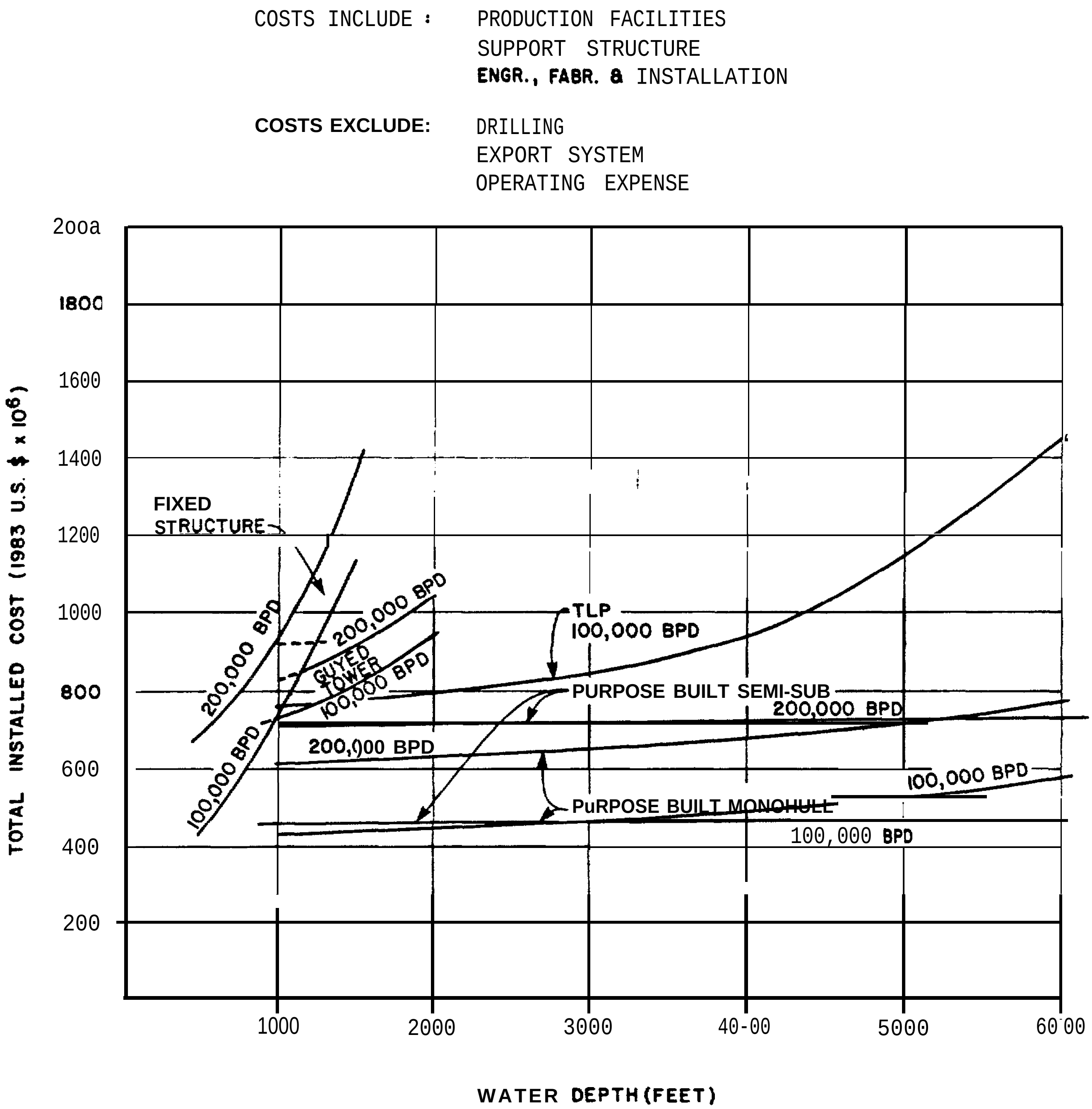
(All Cost in 1983 $ Millions)

Exploration Costs:	126	
Production Platform:	1,440	(Two Platforms)
Platform Well Cost:	700	
Pipeline to Shore:	450	
Intrafield Pipeline:	10	
Total Estimated Development Costs:	2,726	
Annual Operating Cost:	72	

FIGURE 3-3

DEVELOPMENT PLATFORM COST

GULF OF ALASKA



4.0 PETROLEUM TECHNOLOGY ASSESSMENT - ST. GEORGE BASIN

4.1 Influencing Factors

The St. George Basin is probably the most moderate of the three planning regions in this study. With the exception of sea ice, the wave heights are comparable to or slightly less than the other two regions. The seismic effects are significantly less than those in the Gulf of Alaska and comparable to the Navarin Basin. Potential field developments in this basin are next to existing ports which could be expanded for hydrocarbon production.

4.1.1 Environment

The physical environmental parameters that were utilized as benchmark characteristics for technical assessment in the St. George Basin are summarized in Table 4-1.

Maximum wave heights in St. George Basin were taken as comparable to those in Navarin. Specific site characteristics will be influenced by the presence of the Aleutian Islands to the south and the nearby ice presence limiting fetch from the north during the stormy winter months. References 1, 5, 6, 10, 13, and 14 provide insight into wave states assumed for assessment in this region.

References 11, 13 and 14 indicate the extent of sea ice approximately follows the 200-meter water depth contour as shown in Figure 4-1. However, a closer look at the ice coverage in the region has been accomplished by combining ice coverage information from Reference 14 with a basin location map taken from Reference 13 in order to arrive at Figure 4-2. The ice coverage statistics are based on detailed Naval Sea charts from 1972 to the present. Figure 4-2 shows that most of the region beyond the 200-meter contour is statistically ice-free. However, a portion of the region may have 3/10 ice coverage for one-fifth (20%) of the time during the month of March. For the remainder of the time, there

TABLE 4-1

BENCHMARK ENVIRONMENTAL PARAMETERS
ST. GEORGE BASIN

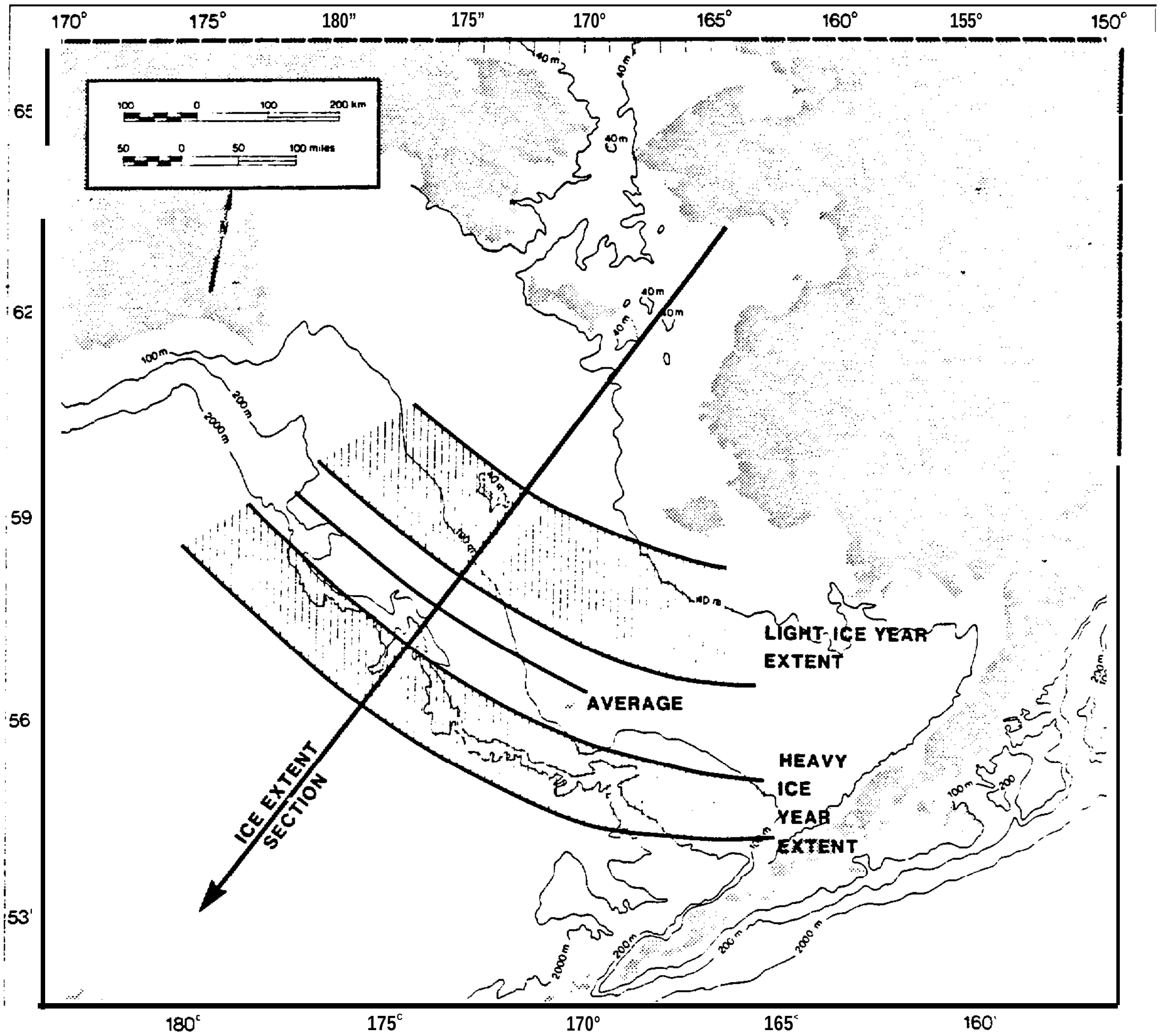
ENVIRONMENTAL PARAMETER	DESCRIPTION
Sea Ice	Max. Areal Coverage = 30% very near to 200 M. Contour 20% of time in month of March; consolidated rafted floe thickness = 1.40; Static Gloval Load = 70 k/ft.
Superstructure Ice Accretion	Assume Design Thickness for "Stationary" structures = 10 cm (4 in.)
Ambient Temperature	Extreme Air = -30°C To +25°C Mean Air = 12°C To +10°C Mean Water = 0°C To +10°C
Wind Speed (l-minute average)	10 yr. = 150 km/h (95 mi/h) 100 yr. = 200 km/h (125 mi/h)
Wave Height & Period (100-year return)	Max. = 25 m; 16 Sec Period Sig. = 14m; 12 Sec Period
Current	Avg. Surface Current = 1 knot Storm Current = 2.5 knots
Tide	1.2m (4 ft.)

TABLE 4-1 (Continued)

BENCHMARK ENVIRONMENTAL PARAMETERS

ST. GEORGE BASIN

ENVIRONMENTAL PARAMETER	DESCRIPTION
Seafloor Profile	Fairly steep gradients of 3° or more from about the 170-meter contour to the 1600-meter contour
Geotechnical Considerations	Clayey silt in North; more standy silt in South; potential for sadiment instability
Seismicity	API Seismic Zone 3 = 0.20 g. Horiz. Ground Acceleration

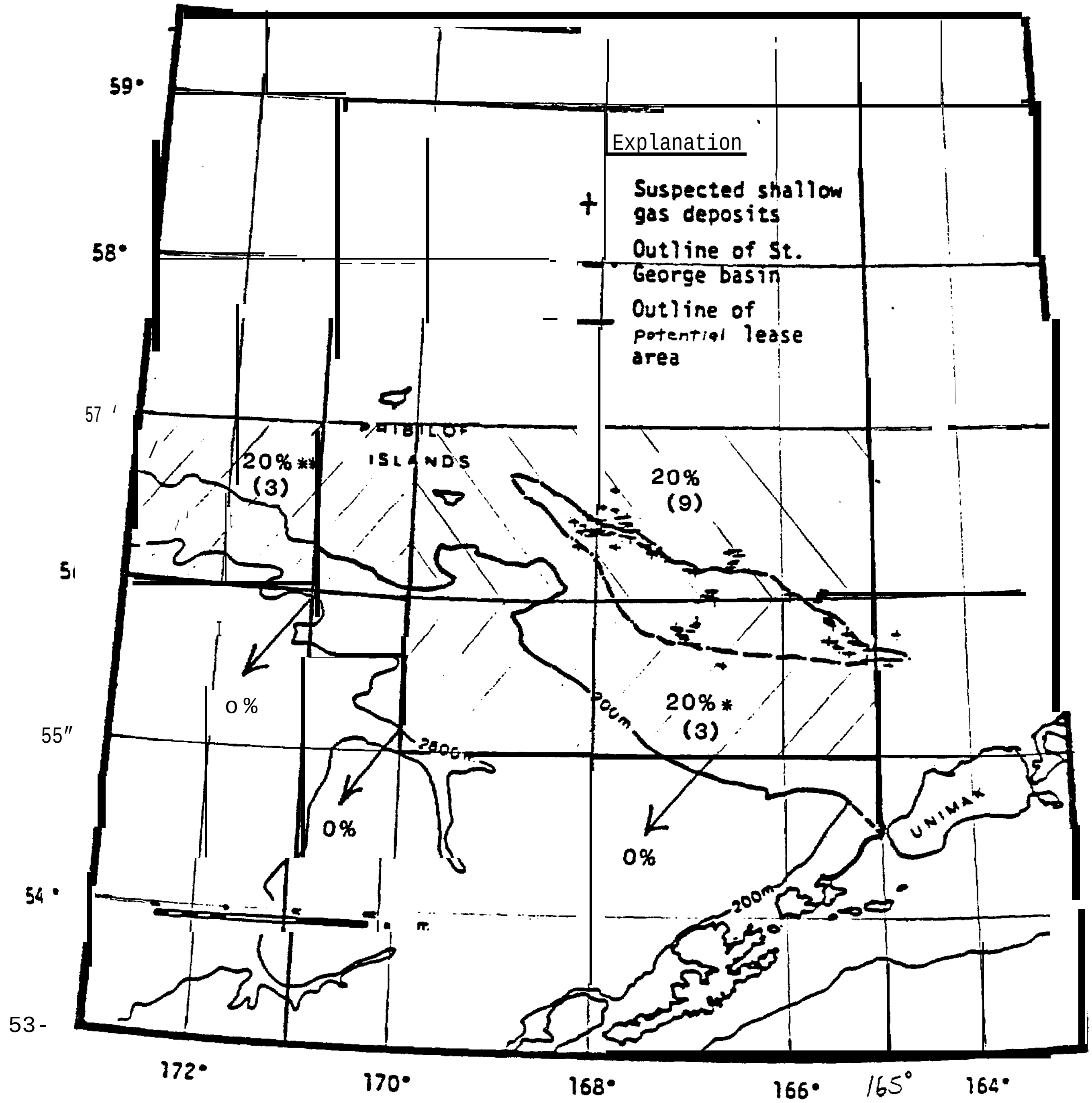


Section along **which** maximum ice extent was computed, and extrapolated zones of minimum and maximum ice extent for this quarter century relative to the section. **(Ref. 14)**

-1

FIGURE 4-1

ICE EXTENT MAP



LEGEND:

Frequency Ice Found in Region During March

( ) Avg. Ice Concentration in Tenths of Spatial Coverage when Ice was Present During March.

* 0% In All Other Months

** 22% (1), In Feb.; 0% Remainder of Time

Ref. 13 of T.M. DW-1 for Map; Ref. 14 of T.M. DW-1 for Ice Coverage

FIGURE 4-2
ST. GEORGE BASIN LOCATION MAP

MAX. ICE COVERAGE (MONTH OF MARCH)

is effectively no ice in these shaded areas, except that a very small region near the Pribilof Islands may experience more ice coverage for a longer period of time. Since there are areas beyond the 200-meter contour which may occasionally see sizeable ice floes around March of each year, then the more conservative assumption of considering global, as well as local, ice loading on production structures in the region appears to be more advisable. Such an assumption would be similar to the conditions assumed for shallower parts of St. George Basin.

From Section 5.0, it has been assumed that the average, maximum, consolidated sheet floe traversing the Navarin Basin study region is 1 meter and that double that value gives a design consolidated rafted floe thickness of 2 meters (6,5 ft). Also, several researchers have confirmed thickness values in the range of 1-2 meters for rafted floes in the northern Bering Sea (References 45, 46). Taking a similar approach for St. George Basin, we find that 70 cm (2.30 ft) is an average maximum value given for an undeformed sheet ice in the southern Bering Sea (Reference 10). Doubling this value, we arrive at 1.40 m (4. 60 ft) for the design consolidated rafted floe thickness in the region. From available data on temperature, salinity, strain rate, and grain structure of the ice in the deep water portions of the Navarin and St. George Basins, the compressive ice strengths were considered similar. Therefore, the design St. George ice loading was taken as a proportion of the Navarin ice load by a ratio of ice thicknesses in the two regions. Accordingly, the St. George design ice load can be approximated as 0.7 (1.40/2.0) of the design Navarin Basin ice loading (see subsection 5.1.1).

Superstructure icing is a possibility in this study region, possibly occurring as much as 50% - 60% of the time in late winter (Reference 13). Loads imposed are assessed in a manner similar to that described for the Gulf of Alaska in Section 3.0.

Soils data is somewhat limited for this region. As with Navarin Basin, seabed sediments beyond the shelf break, near the 170-meter contour in St. George Basin, are susceptible to slumping and sediment instability because of the rather steep seafloor gradients. The seafloor is thought to slope at about a 3° gradient out to the 1600-meter. contour (Reference 14). The shear and bearing strenghs of the seafloor sediments are expected to be greater than those in Navarin Basin based on the descriptions in References 1, 11, 13 and 14.

The seismicity of this region is moderately high and is classified as API Zone 3 with a 0.20 g. peak horizontal ground acceleration.

4.1.2 Logistics

The St. George Basin deepwater areas are not as remote as Navarin Basin from potential support bases. The center of the basin lies approximately 240-320 kilometers (150-200 miles) from both the Pribilof (St. Paul and St. George) Islands and from Dutch Harbor in the Aleutians. Cold Bay on the extreme tip of southwestern Alaska Peninsula and Dutch Harbor on Unalaska Island are likely support base locations. Makushin Bay has been suggested as a possible pipeline terminus and facilities site (Reference 13).

References 2 and 13 describe the logistics details for this region.

4.2 Exploration Systems

Exploration in the St. George Basin will be achieved with drilling rigs develped specifically for cold, harsh environments. Of the three study areas, St. George Basin ranks as more difficult than the Gulf of Alaska, but not quite as difficult as Navarin Basin in terms of environmental conditions and logistical restraints.

4.3 Production System Components

Production system components utilized in this study region must possess the capability to withstand the seismic and ice loads anticipated. Even though the seismic effects are less than those in the Gulf of Alaska, there is a possibility of sea ice which must be considered. This combination of factors is reflected in increased development costs over the Gulf of Alaska. Distance from potential onshore terminals and long pipelines to shore would tend to favor offshore loading and storage, at least for initial developments.

4.4 Typical Production Scenario

A typical production scenario similar to that in Section 3.0 for the Gulf of Alaska is outlined in Table 4-2. Essentially, this scenario includes two (2) production platforms for a total of 200,000 BOPD and export through a pipeline to an existing onshore terminal.

4.5 Cost Estimates

Estimated costs for the scenario outlined in Section 4.4 are presented in Table 4-3. The basis for these costs was derived from the later sections in this study. The costs for production systems in St. George Basin are shown in Figure 4-3.

TABLE 4-2

TYPICAL PRODUCTION SCENARIO

ST. GEORGE BASIN

Exploratory Wells:	6
Production Rate:	200,000 BOPD
Water Depth:	300 Meters (1,000 feet)
Distance From Landfall:	320 Km (200 miles)
No. of Platforms:	Two
No. of Platform Wells:	100 (incl. producing & injection)
Pipelines:	To existing developments plus intrafield between platforms

TABLE 4-3

PRODUCTION SCENARIO COSTS

ST. GEORGE BASIN

(All Cost in Millions of $ 1983)

Exploration Costs:	144
Production Platform:	1,480
Platform Well Cost:	800
Pipeline to Shore:	480
Intrafield Pipeline:	50
Total Estimated Development Costs:	2,954
Annual Operating Cost:	92

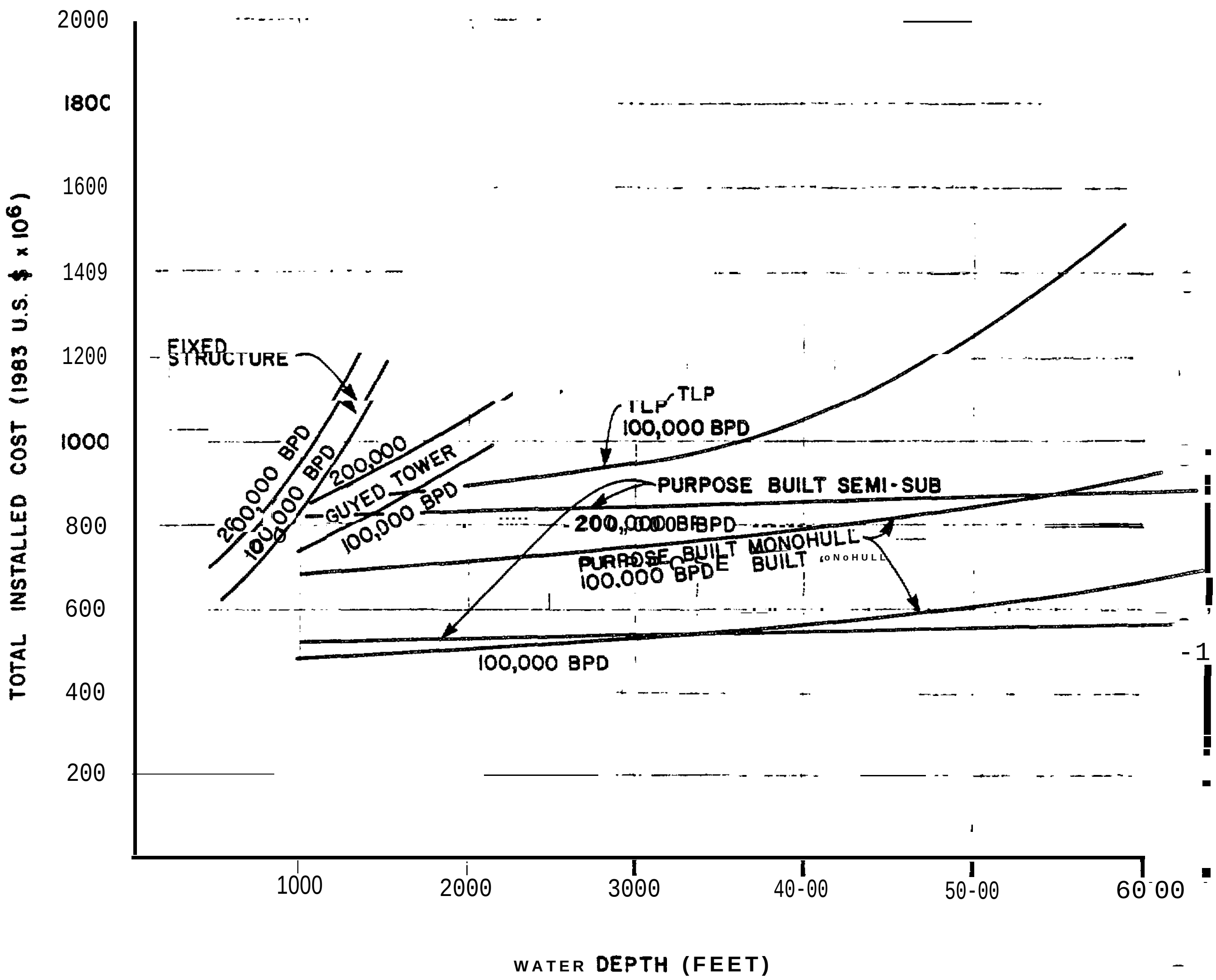
FIGURE 4-3

DEVELOPMENT PLATFORM COST

ST. GEORGE BASIN

COSTS INCLUDE : PRODUCTION FACILITIES
SLIPPORT STRUCTURE
ENGR., FABR. & INSTALLATION

COSTS EXCLUDE : DRILLING
EXPORT SYSTEM
OPERATING EXPENSE



5.0 PETROLEUM TECHNOLOGY ASSESSMENT RESULTS - NAVARIN BASIN

5.1 Influencing Factors

out of all of Alaska's OCS basins, the Navarin Basin has been ranked second behind the Beaufort Sea in terms of hydrocarbon potential (Ref. 2). However, the Navarin Basin appears to have the most severe combination of characteristics of the three different regions in this study with respect to remoteness, sea ice, low ambient air and water temperatures, steep seafloor gradients and soft soil strengths. The wave severity is also significant since it approaches the extreme values found in the Gulf of Alaska.

5.1.1 Environment

Assumed wind and wave estimates were derived by comparing extremes presented in References 5 and 6 by using estimates made recently by Dames & Moore in Ref. 1. These values are given in Table 5-1 and are similar to the design criteria for the North Sea. Other relevant meteorological parameters such as ambient air and water temperatures, ice accretion on the superstructure, and tide and current levels are also given in Table 5-1. A more detailed description of the ice accretion phenomenon is given in Section 3.0.

Sea ice conditions will be a major consideration in Navarin Basin. Sea ice begins forming in the extreme northern Bering Sea in November and then gradually spreads south-southwestwards. In addition, ice floes from the Chukchi Sea may move southward through the Bering Strait under the influence of strong northeasterly winds. The combination of ice sources creates an ice morphology of small floes surrounded by broken ice pieces, the latter probably resulting from the impact of floes with one another. The maximum ice extent in Navarin Basin is reached in the March-April period, as shown in Figure 5-1 (References 1, 6, 10, 11, 12). The northern half of Navarin can expect sea surface coverages approaching 60%

TABLE 5-1

BENCHMARK ENVIRONMENTAL PARAMETERS

NAVARIN BASIN

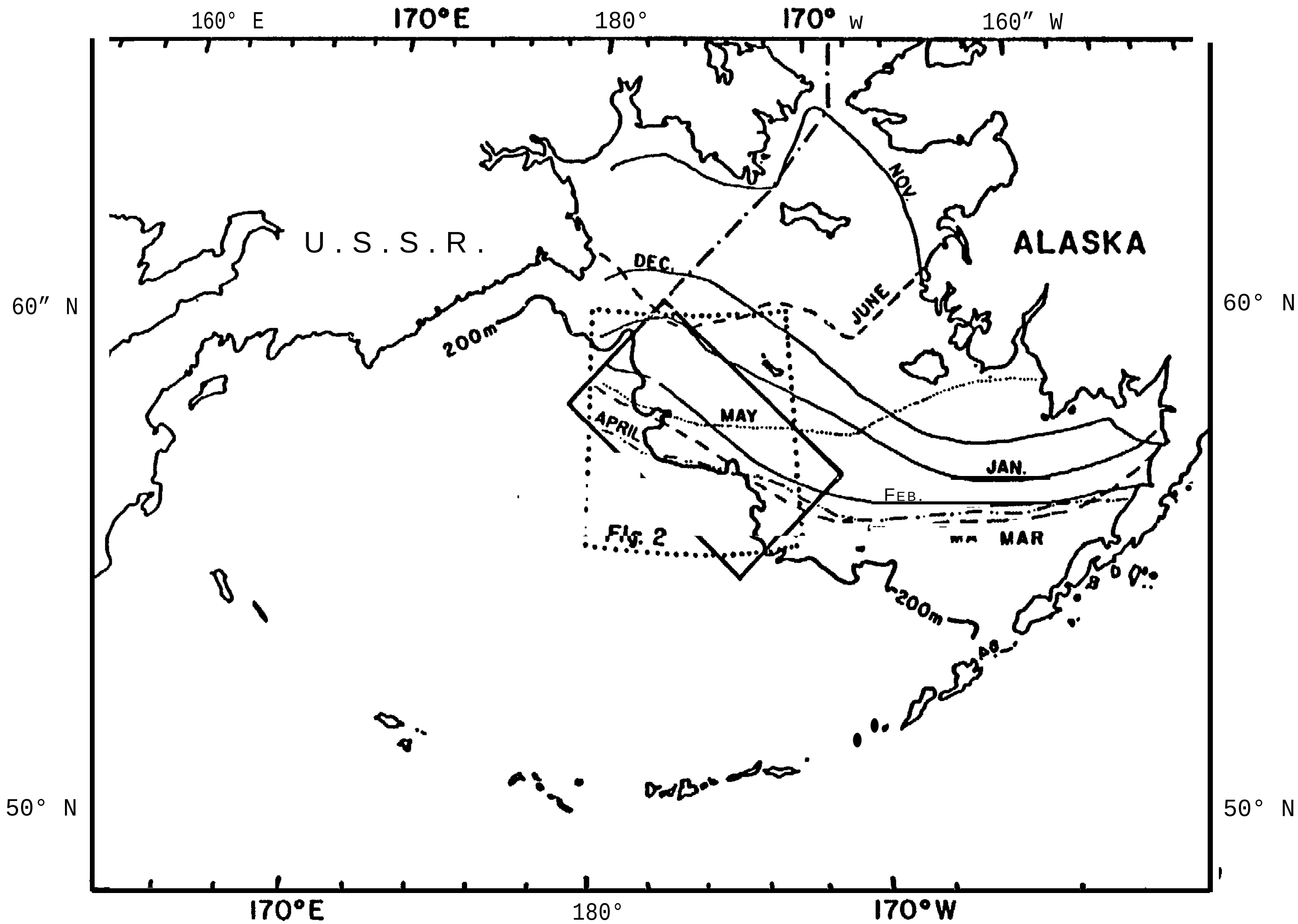
ENVIRONMENTAL PARAMETER	DESCRIPTION
Sea Ice	6 month season (Dec.-May); Max. coverage 60-70% in March-April; consolidated rafted floe thickness = 2.0 meters, Static Global Load = 100 k/ft.
Superstructure Ice Accretion	Assume Design Thickness for "Stationary" structures = 10cm (4 in.)
Ambient Temperature	Extreme Air = 30°C To +25°C Mean Air = 12°C To +10°C Mean Water = 0°C To +10°C
Wind Speed (l-minute average)	10 yr. = 150 km/h (95 mi/h) 100 yr. = 200 km/h (125 mi/h)
Wave Height & Period (100-year return)	Max. = 27m; 16 Sec Period Sig. = 15 m; 12 Sec Period
Current	Avg. Surface Current = 1 knot Storm Current = 2.5 knots
Tide	1.2 m (4 ft.)

TABLE 5-1 (Continued)

BENCHMARK ENVIRONMENTAL PARAMETERS

NAVARIN BASIN

ENVIRONMENTAL PARAMETER “	DESCRIPTION
Seafloor Profile	Very steep gradients, ranging from 3° to 8° from about the 150 meter contour to the 2800 meter contour
Geotechnical Considerations	Weak soil conditions; silty clay with shear strengths of about 0.1 KSF near surface to 1,0 KSF at depth; high sediment instability potential
Seismicity	API Seismic Zone 1 = 0.05 g. Horiz. Ground Acceleration



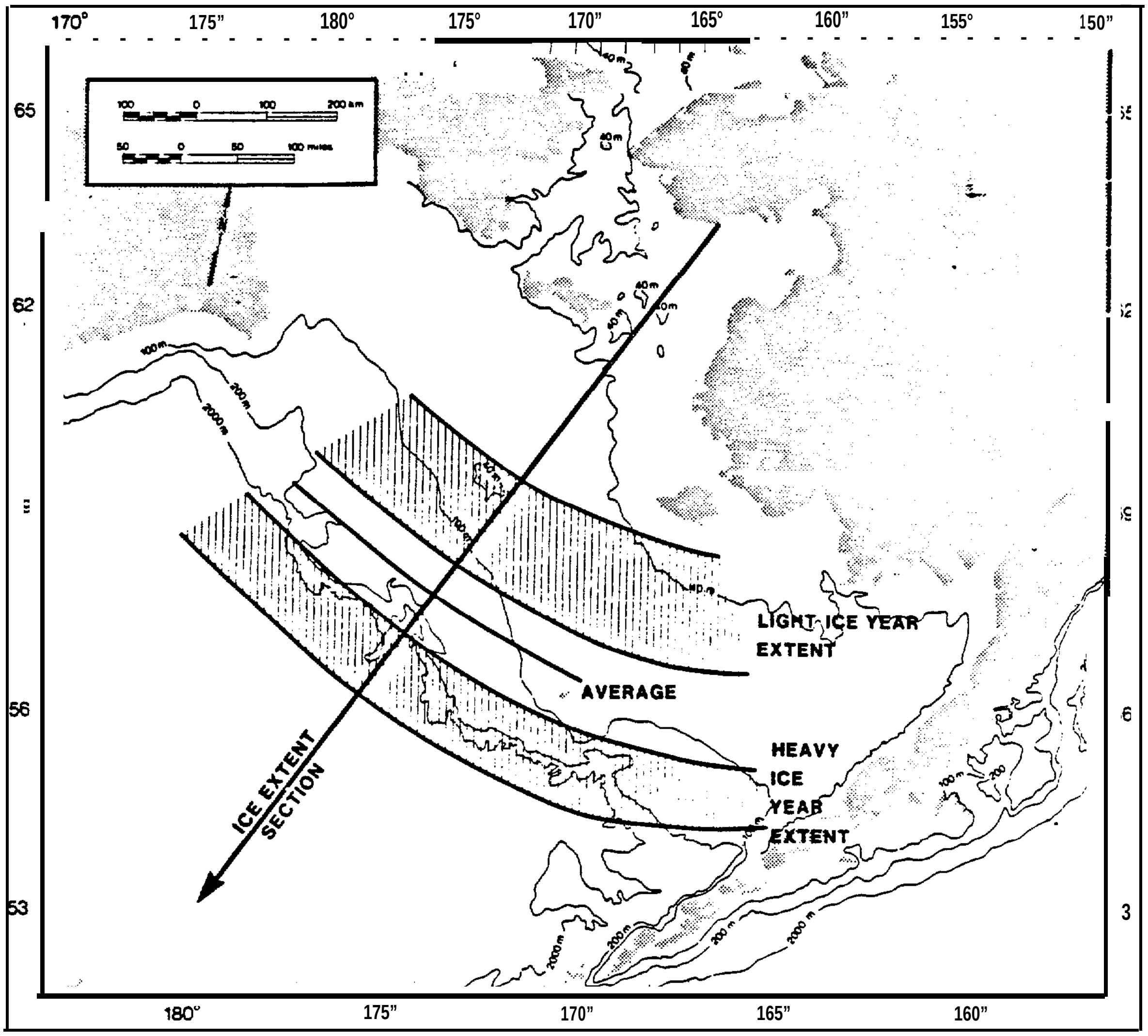
Location of Navarin Basin province (outlined) and lines of average monthly ice-front positions (aHer Webster, 1979); ice positions for the 15th of month

LOCATION OF **NAVARIN** BASIN PROVINCE

FIGURE 5-1

to 70%, while the southern half may experience lesser ice coverage beyond the 200-meter contour. In light ice years, there may be no ice at all beyond the 200-meter contour throughout most of the basin. However, during the most severe ice years, the entire Navarin study region is within the limit of maximum ice extent as indicated in Figure 5-2 (Reference 14). Figure 5-3 shows the mean ice concentrations in the area during the early April time period when the ice coverage is normally at its greatest levels. Figure 5-4 shows the percentage of area covered with large floes during the same period (Reference 47). One will note that the deep water portions of Navarin Basin appear to have less than 10% areal coverage with the large floes during this peak ice period.

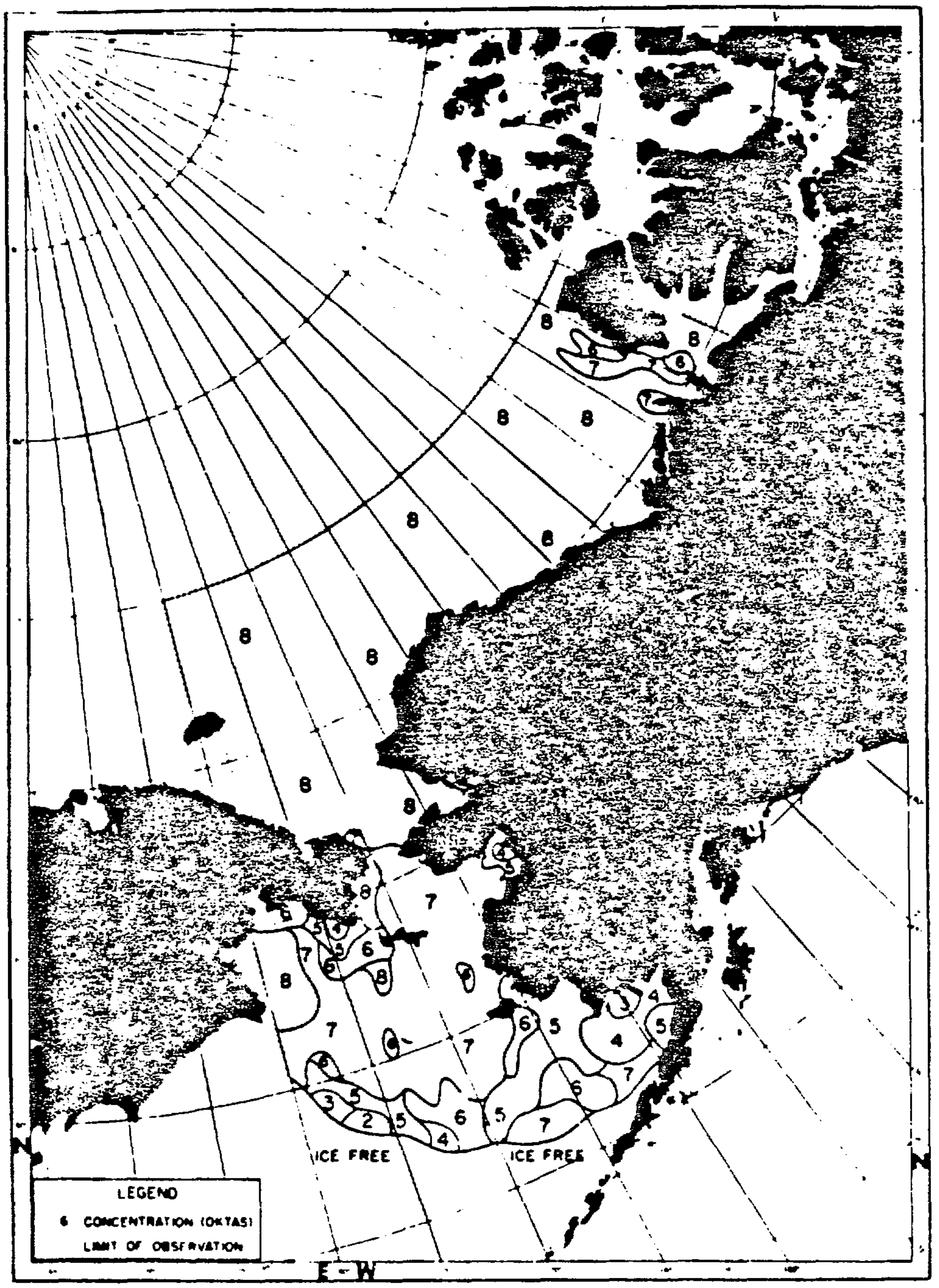
In the Navarin Basin it has been assumed that the average, maximum, consolidated sheet floe traversing the study region is 1.0 meters thick and double that value to arrive at the design, consolidated, rafted floe thickness of 2.0 m (Reference 45, 46). Properties for the design ice floe were derived from References 48, 49 and 50 and recommendations by Schwarz and Weeks (Reference 51). In summary, Beaufort Sea ice compressive strength values may be reduced by approximately one-half for average ice temperatures approaching the sea water freezing point, as is expected for Bering Sea annual sheet ice near the ice edge. Thus, a design ice compressive strength value of 200 psi has been determined as being appropriate for purposes of this study, assuming ice crushing as the failure mechanism. When this value is combined with the design ice thickness and structure interaction parameters in Korzhavin's ice indentation formulation, as described in numerous references such as Reference 49, then a design ice force of approximately 100 kips per foot of structure interaction width is determined. This is the value that formed the basis for evaluating the effects of sea ice on the various structural systems considered for use in development of Navarin Basin.



Section along which maximum ice extent was computed, and extrapolated zones of minimum and maximum ice extent for this quarter century relative to the section (REF. 14)

ICE EXTENT MAP

FIGURE 5-2



MEAN ICE CONCENTRATION 1 — 15 APRIL

MEAN ICE CONCENTRATION

FIGURE 5-3

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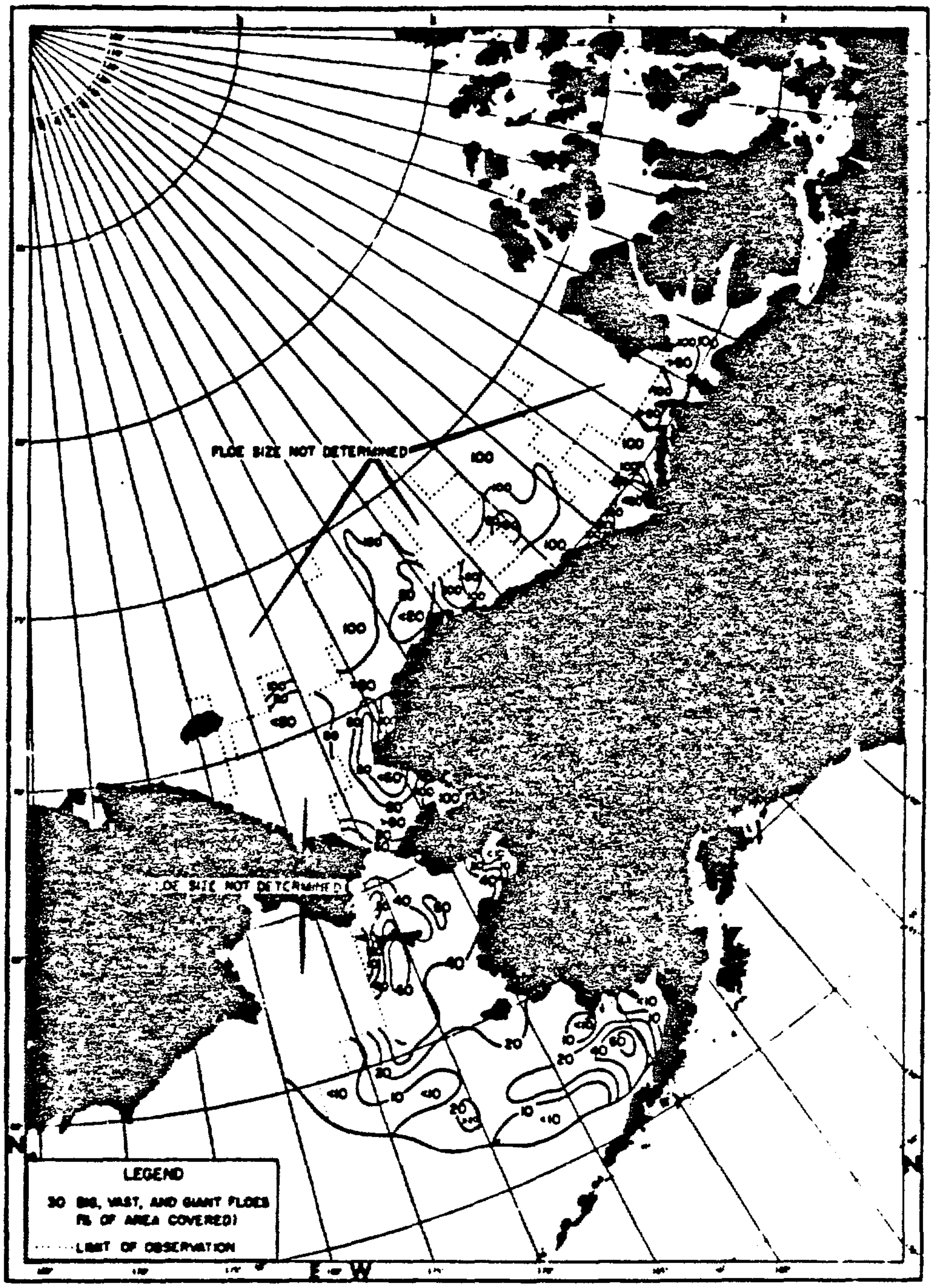


MEAN FLOE SIZE PERCENTAGE 1—15 APRIL

MEAN FLOE SIZE CONCENTRATION

FIGURE 5-4

The assumption of ice crushing as the failure mechanism may be somewhat conservative in cases where the structural design is such as to induce bending in the interacting ice feature. Complete bending, however, cannot always be assured due to friction during ride-up, ice pile-up at the structure, etc., and therefore, at least some mixed mode failure seems to be a prudent design assumption. Accordingly, crushing failure is a probable assumption when the various types of structures are considered as a whole in the context of this study.

The sea floor profile of this study region is characterized by relatively steep slopes as the continental shelf break begins at the 150-meter isobath and extends to a depth of 2800 meters (9,200 ft) (Ref. 11). Three major submarine canyons traverse the region. The shear strength of the mudline sediments appears to be quite low ranging from about 11 Kpa near the shelf break to about 3 Kpa near the abyssal floor (Ref. 11). The combination of steep slopes and weak sediments appears to make many parts of the area susceptible to submarine sediment slides. This phenomena must be considered in the design of bottom-founded structures, mooring systems, sub-sea trees and flowlines. In fact, this combination of geotechnical parameters effectively eliminates the use of gravity base structures and, to a certain extent, increases the structural requirements of piled structures beyond what is typical in the majority of offshore regions elsewhere in the world. The seismicity of the region appears to be quite low and is classified by API as Zone 1 with a 0.05 g peak horizontal ground acceleration.

5.1.2 Logistics

Navarin Basin is the most remote of the study regions. The nearest landfall from deepwater in Navarin Basin is St. Matthew Island which is about 250 kilometers (150 miles) distant. St. Matthew Island is currently a National Wildlife Refuge and has no facilities or human population (Ref. 1).

Other potential support bases are considerably more distant. For example, Nome was used by ARCO in a recent COST exploration well in Navarin Basin even though Nome is located over 640 kilometers (400 miles) from the well site (Ref. 4). Dutch Harbor in the Aleutian Islands is even men? distant.

5.2 Exploration Systems

The harsh environmental requirements in the Navarin Basin are the most stringent of the three regions in this study. The latest generation drilling rigs are designed and constructed for such a region. Logistical support will also be a major cost influence in this region based on recent experience. Transportation equipment such as long haul helicopters and large capacity supply boats will be a necessity to support an exploratory program.

5.3 Production System Components

For a given water depth, sea ice was the most important influence for platform structure selection in this region. Designs for estimating costs in this region represented the most expensive structural considerations of the three study areas. PI atfo rm structures, mooring systems and production risers were heavily influenced by sea ice effects.

Long distances from landfall would preclude a pipeline to shore since several intermediate pumping platforms would be required. Even the offshore storage and loading systems would require some ice management to ensure a near-continuous operation.

5.4 Typical Production Scenario

A typical production scenario for Navarin Basin is presented in Table 5-2. Two platforms to produce a total of 200,000 BOD are included with an offshore loading and storage system.

TABLE 5-2

TYPICAL PRODUCTION SCENARIO

NAVARIN BASIN

Exploratory Wells:	6
Production Rate:	200,000 BPD
Water Depth:	300 Meters (1,000 Feet)
Distance From Landfall:	620 Km (400 Miles)
No. of Platforms:	Two
No. of Platform Wells:	100 (Incl. Producing & Injection)
Pipelines:	To offshore terminal plus intra-field between platforms

5.5 Cost Estimates

Estimated costs for the scenario outlined in Section 5.4 are presented in Table 5-3. Sections 6.0, 7.0, 8.0 and 9.0 provide the basis for these costs. The costs for productions systems in the Navarin Basin are shown in Figure 5-5.

TABLE 5-3

PRODUCTION SCENARIO COSTS

NAVARIN BASIN

(All Cost in 1983$ Millions)

Exploration Costs:	180
Production Platform:	1,500
Platform Well Cost:	900
Pipeline to Shore:	None
Intrafield Pipeline:	50
Captive Tanker:	90
Total Estimated Development Cost:	2,720

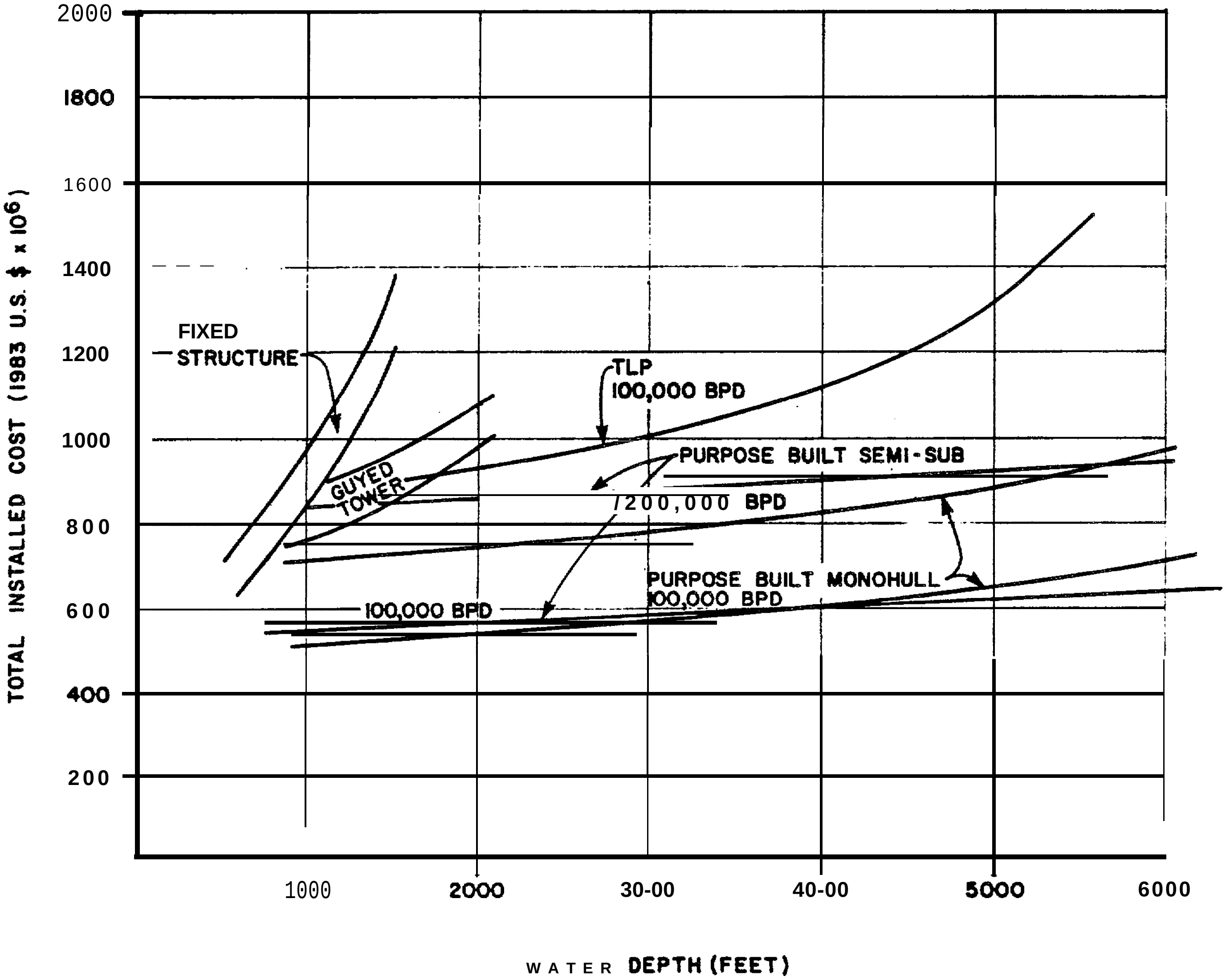
FIGURE 5-5

DEVELOPMENT PLATFORM COST

NAVARIN BASIN

COSTS INCLUDE: PRODUCTION FACILITIES
SUPPORT STRUCTURE
ENGR., FABR. & INSTALLATION

COSTS EXCLUDE: DRILLING
EXPORT SYSTEM
OPERATING EXPENSE



6.0 ASSUMPTIONS FOR EXPLORATION COSTS

6.1 Introduction

Exploration in sub-arctic deep water areas is expected to require more extensive delineation drilling than expected in less harsh environments to justify economic development. The NPC Report in 1981 (Ref. 2) summed up the need for increased seismic surveys to promote a better understanding of the geology and the presence of proven recoverable reserves by drilling. Sub-arctic, deep water environments combined with more extensive delineation drilling to justify commercial development will result in greater exploration costs as compared to other parts of the world.

Methods and equipment development will be influenced by recent exploratory efforts in the Gulf of Alaska and Bering Sea during 1983. A new generation of exploratory drilling rigs for harsh environments is available and more units are in the planning and construction phases. Recent deep water exploration off the U.S. East Coast and in the Mediterranean have provided technology for dynamic positioning riser design and new advances in tensioning equipment.

6.2 References

Extensive use was made of the NPC "U.S. Arctic Oil and Gas Survey Report" published in 1981 (Ref. 2) and numerous industry publications. Deep water exploratory drilling experience and costs were derived from recent experience off the U.S. East Cost (Ref. 27 & 28) and the Mediterranean (Ref. 37). Exploratory efforts offshore Alaska indicate increased cost for sub-arctic drilling (Ref. 23 & 24). Deep well drilling costs worldwide were also reviewed to further develop a credible data base (Ref. 24, 25 & 26). While the industry publications provide ample information on new methods and equipment suitable for sub-arctic exploration, only a selected number are presented in this Section to indicate the trends being followed.

6.3 Influencing Factors for Sub-Arctic Deep Water Exploratory Drilling

The primary factors that will influence deep water exploratory drilling in sub-arctic areas include:

- deep water riser technology,
- sea ice and topside ice accretion environments,
- floating drilling rigs for sub-arctic and deep water operations,
- specially equipped transportation vehicles to traverse the long supply routes, especially in the northern Bering Sea,
- infrastructure development including ports and onshore supply bases

Deepwater riser technology for exploratory drilling has been extended to water depths of approximately 1,830 meters (6,000 ft.) with designs for approximately 3,050 meters (10,000 ft). This technology was developed in response to exploratory projects in the Mediterranean and off the U.S. East Coast {Ref. 37, 38, 39, 40 & 41). The riser is the most highly stressed component involved in drilling and should it fail, all operations must be suspended. Since the chances of failure must be anticipated, a second spare riser is normally available. The cost of this sparing philosophy plus new developments in riser design must be a cost consideration in deep water drilling in relatively remote sub-arctic areas.

Other factors controlling deep water riser design include strength and material selection; riser buoyancy and tensioning equipment; and running and pulling speed.

A new generation of semi-submersible drilling rigs for severe and arctic environments can operate in water depths over 3,000 meters (10,000 ft) and drill wells up to depths of 9,000 meters (30,000 ft) below seabed (Ref. 42). Several of these rigs are currently at work with more under construction or in the design phase. Design features include conventional moo ring systems and dynamic positioning, ice strengthened columns, fewer large stabilizing columns, large displacement and large variable load capacity, high storage capacity to minimize resupply and winterization to enable year-round working in a shirt sleeve environment.

Specially equipped and purpose built transportation methods will be required to overcome and minimize the combined effects of a severe environment and remote drilling locations. Extended range helicopters which are capable of round trip operations without refueling will be necessary for crew changes. Large, arctic rated supply vessels will be required to resupply the rigs in the fewest trips and to provide possible assistance for ice management in the northern Bering Sea areas.

Continued exploration activity in sub-arctic areas is expected to lead to improved infrastructure similar to developments in Prudhoe Bay. Strategically located onshore supply bases and storage areas will tend to reduce the transportation costs as dictated by demand. However, expenditures for such facilities will ultimately be driven by commercial discoveries leading to field development.

Repair facilities to service the drilling and supply vessels will be required. Unless there is a significant demand, existing drydock and repair facilities in other parts of the world will continue to be utilized. Existing airports may require expansion to handle the crew and cargo requirements.

6.4 Summary of Exploration Costs

Exploration costs generally increase from south to north in the three (3) study regions with the least expensive costs being associated with the Gulf of Alaska and the most expensive with the Navarin Basin. This trend is due primarily to the remoteness of these regions from onshore supply bases and the associated logistics expenses. Two recent examples in 1983 include the Yakutat No. 1 exploratory well in the eastern Gulf of Alaska with a cost of about $42 million (Ref. 23) and the Navarin COST Well No. 1 at an estimated cost of $57 million (Ref. 22). These projects were considered deep wells - approximately 4,200 to 5,500 meters (14,000 ft to 18,000 ft) - drilled in approximately 120 to 140 meters (400 to 450 ft) of water. The first deep water exploratory well drilled on the U.S. outer continental shelf was completed off the U.S. east coast in 1983. This effort reportedly cost more than $200,000 per day (Ref. 28) for a water depth of approximately 2,000 meters (6, 500 ft) and total well depth of approximately 4,500 meters (14, 500 ft).

The Navarin COST Well No. 1 reportedly required two (2) specially equipped, extended range helicopters to effect crew changes. These helicopters cost considerably more than $9 million each (Ref. 22) and could traverse the approximate 1,450 kilometers (900 mile) round trip without refueling. A third smaller helicopter was stationed onboard the drill rig as a medical evacuation aircraft. This helicopter was specially equipped with extra fuel tanks to cover the more than 400 mile distance to shore.

6.5 Development of Sub-Arctic Deep Water Exploration Costs

Drilling costs for deep wells drilled in 1982 to 15,000 feet or deeper were reported in References 25 & 26. These figures varied from a low of about $1600 per foot of well drilled to a upper value of over $4,000 per foot offshore Canada. A deep water exploratory well drilled on the U.S. East Coast OCS in 1983 was reported to have cost more than $200,000 per day, which translates to a cost of about $1,600 per foot (Ref. 27 & 28). By comparison, the deep water Mediterranean well cost over $2,300 per foot with an apparent rig rate of $242,000 per day. The sub-arctic deep wells drilled in the Bering Sea and Gulf of Alaska during 1983 yielded costs which likely reflect the trends for exploratory operations in this region (References 22 & 23). These costs are presented in Table 6-1 and substantiate the fact that deep water exploration offshore Alaska is an obviously expensive proposition, with daily drilling rates approaching $400,000 per day in the remote regions of the Bering Sea.

Costs used in this study are based on improved infrastructure and logistics and the availability of more harsh environment drilling rigs, however the costs associated with improvements in logistics have also been considered. The following rates were assumed in development of the exploratory drilling costs in Figure 6-1:

- Gulf of Alaska: $200,000 per day
- St. George Basin: $225,000 per day
- Navarin Basin: $250,000 per day

The main variable in the above daily rates are the anticipated logistics and supply costs. Factors such as holding rigs over the winter months, lack of supply bases and ice management support vessels could cause increases of 40% to 100% of these costs.

TABLE 6-1

SUMMARY OF OFFSHORE EXPLORATORY DRILLING

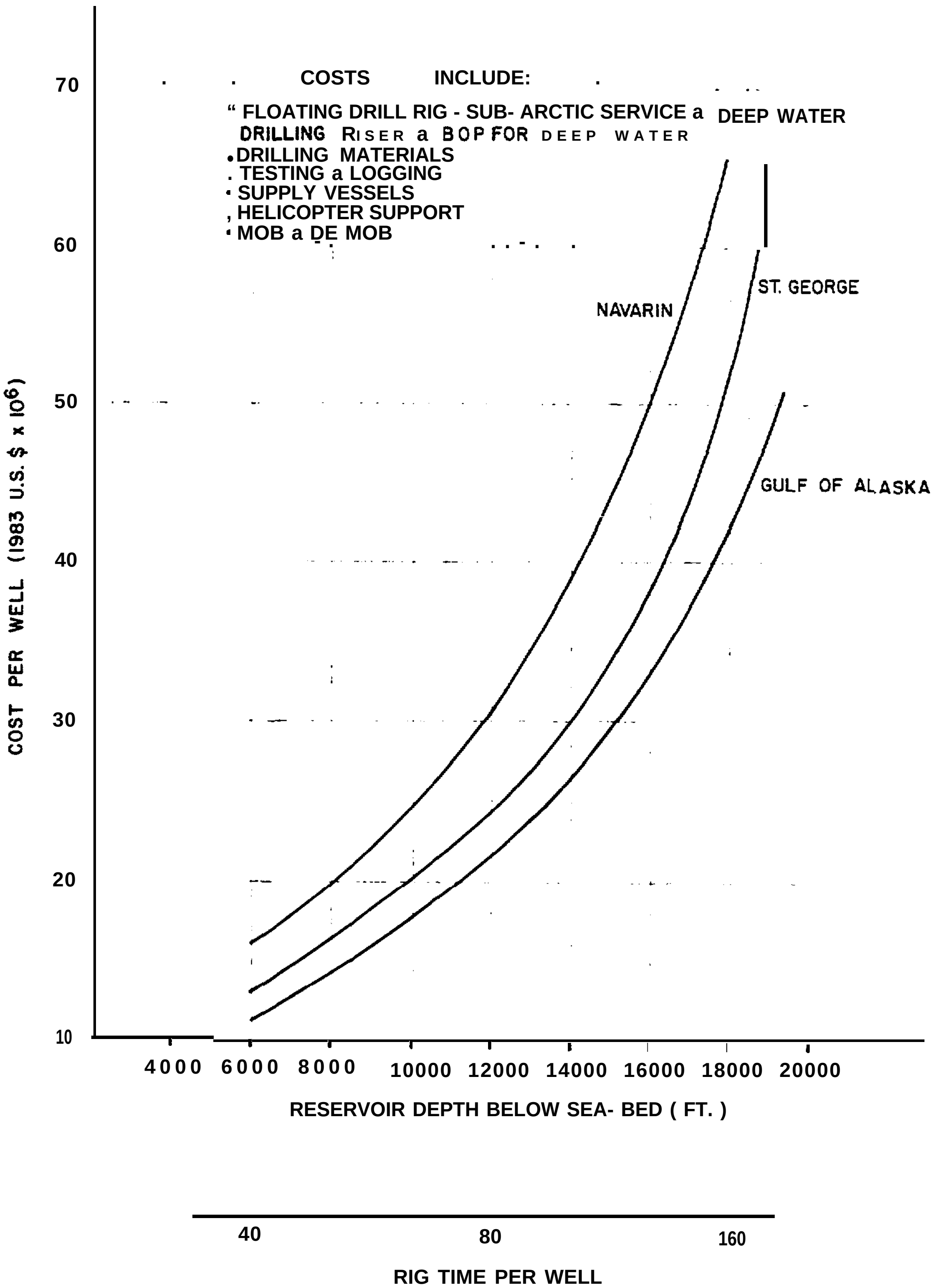
Location & Operator	Water Depth (Meter/Feet)	Drill Depth (Meter/Feet)	Drill Time (Days)	Total Cost ($ x 10^6)	Estimated Day Rate	Estimated Cost per Foot (2)
US East OCS by Shell	2, 070/6, 800	4, 500/14, 500	120	24	over 200,000 (1)	1,600
Mediterranean by TOTAL	1, 700/5, 600	1, 890/6, 200	60	14.5 (1)	242,000	2,340
Eastern Gulf of Alaska; Yukutat No. 1 by ARCO	1 40/450	5,000/16,400	150	42 (1)	380,000	2,560
Bering Sea; Navarin COST Well No. 1 by ARCO	130/420	4, 500/14, 500	180	57 (3)	316,000	3,900
				100 (4)	555,000	6,900

NOTES: (1) Published costs -1983$

(2) Costs estimated from published data (multiply by 3.28 for cost per meter)

(3) Includes only drilling time on location

(4) Includes added costs for mob, demob and wintering rig over off-season



SUMMARY OF OFFSHORE EXPLORATORY DRILLING

FIGURE 6-1

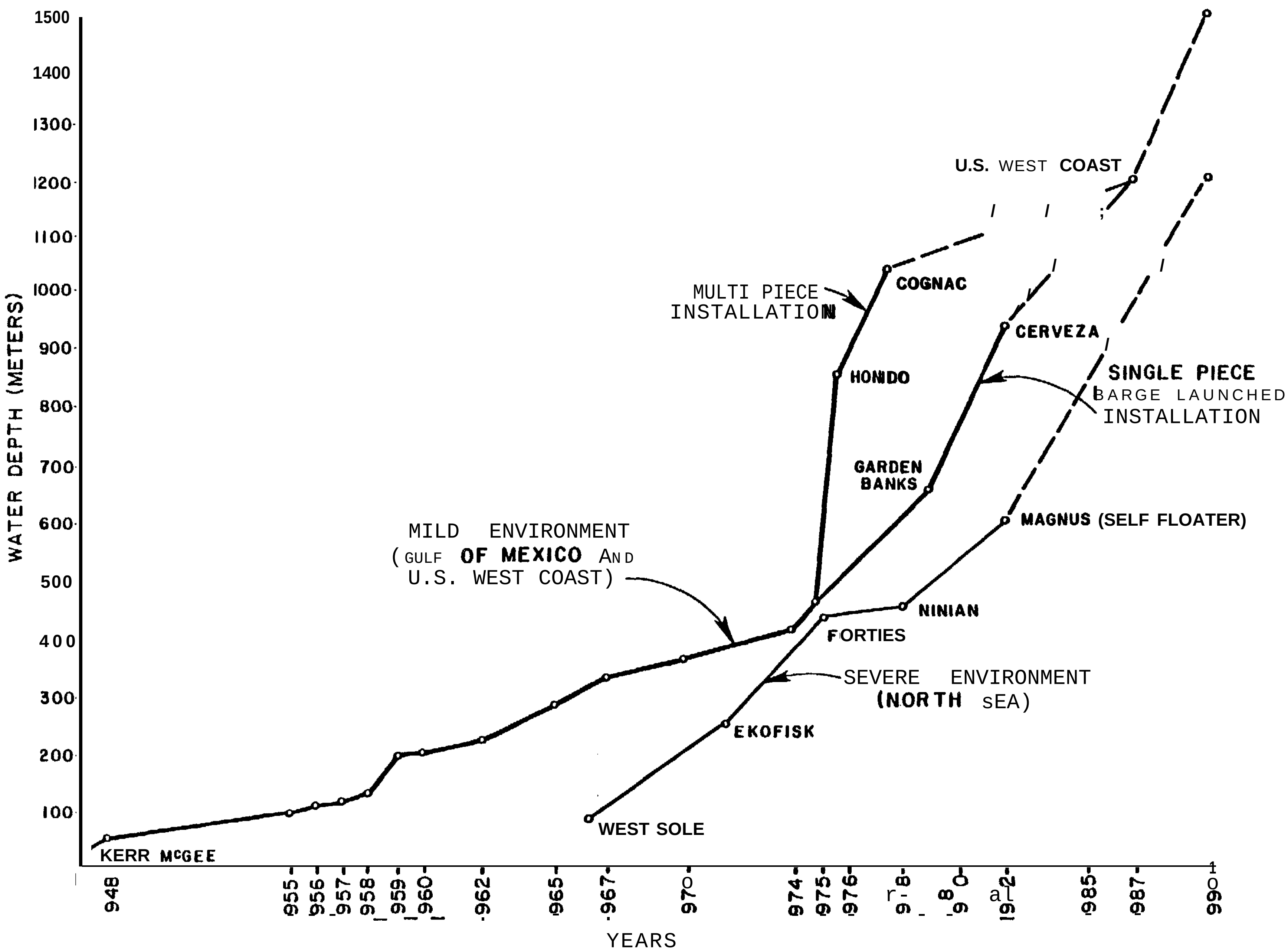
7.0 ASSUMPTIONS FOR PLATFORM STRUCTURE COSTS

7.1 Introduction

Platform support structures for drilling and production facilities can be classified either according to their type of foundation suPport, i.e. , bottom-founded or floating, or according to their degree of compliance with environmental forces. As water depths increase, the weight and complexity of conventional piled support structures increase to cope with fatigue and wave-induced dynamic stress amplifications. Alternatives to these fixed platforms are well advanced, and, in deeper waters, they may be replaced by lighter, compliant structures that are more flexible and tend to move with the wave forces. This property of compliant structures significantly reduces the associated wave-induced dynamic amplifications of stress and fatigue and results in lower tonnages of structural materials as compared to conventional piled structures. The evolution of platforms with respect to water depth over the past three decades is shown in Figure 7-1.

In this section, the use of conventional bottom founded platforms (piled, gravity and hybrid) will be explored along with the compliant guyed towers, tension leg platforms (TLP) and floating production systems (semi-submersibles and monohull s).

Support structures suitable for deep water, sub-arctic areas must not only cope with the deep water and severe wave action but also with varying degrees of sea ice, seismic loads, superstructure icing and unstable, sloping seabed conditions. These major influencing factors plus other considerations for topside loads and number of wells are presented in Section 7.3. Estimated costs are presented in Sections 7.4 and 7.5.



WATER DEPTH VS. YEARS. FIXED JACKETS

FIGURE 7-1

7.2 References

The data base for support structures reveals that the piled, space-frame, jacket structure has been the most commonly used offshore drilling and production structure worldwide. Such structures have been used exclusively in U.S. waters in the Gulf of Mexico and offshore California while they have shared the development role in the North Sea with the concrete gravity base structure. The world's first commercial guyed tower was installed in the Gulf of Mexico in 1983, and the world's first tension leg platform is scheduled to be installed in the North Sea in late 1984. The state of the art for platform support structures is outlined in Table 7-1.

7.2.1 Conventional Structures

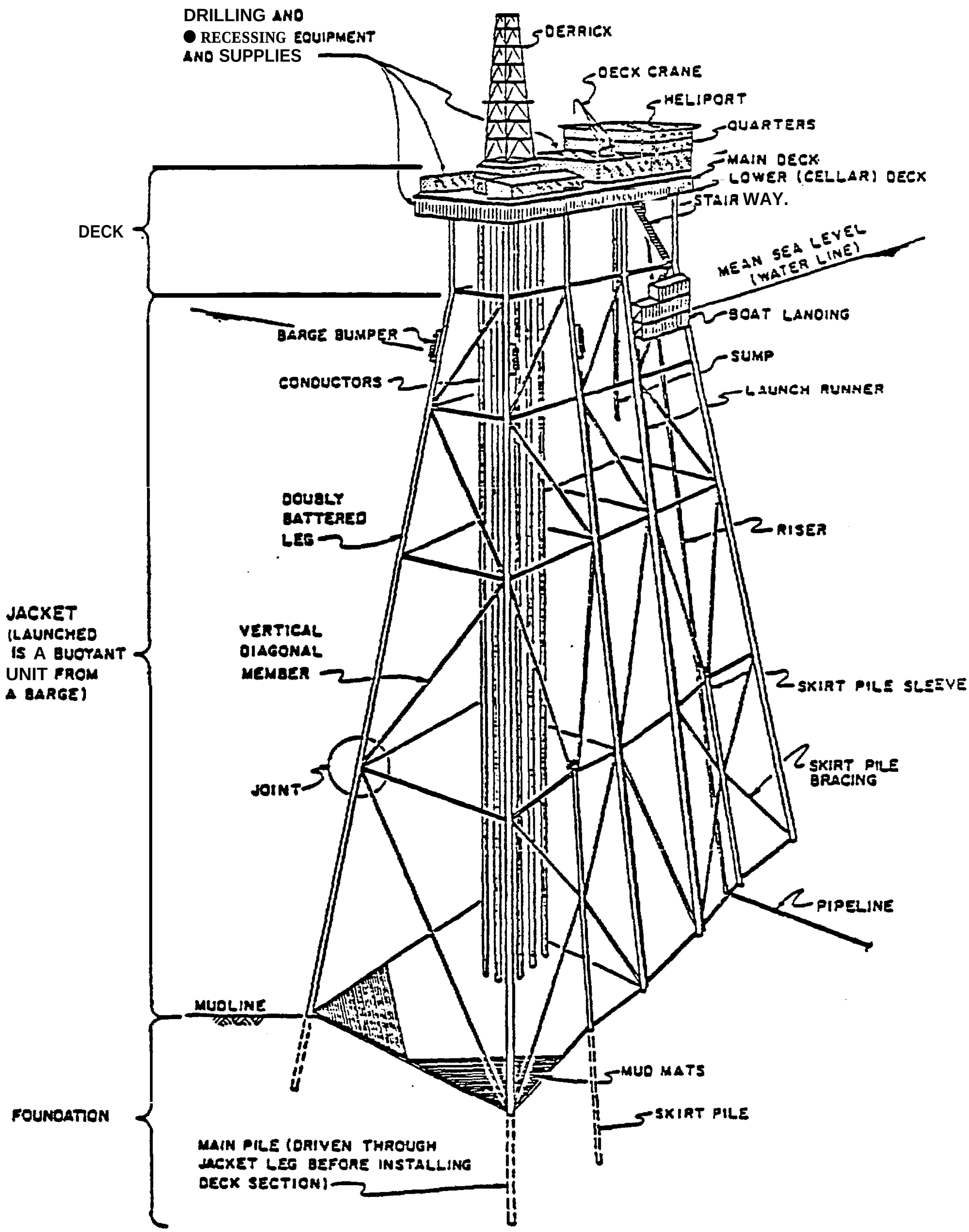
The jacket structure typically consists of relatively large diameter steel tubular legs located at well-spaced intervals around the perimeter of the platform. These legs are braced with smaller diameter tubular members running in the "vertical" planes between the legs. The legs are normally battered or sloped at a slight angle off the vertical so that the bottom of jacket dimensions are significantly larger than those at the top of the jacket. The jacket foundation consists of piling installed through the main legs and penetrating on the order of several hundred feet into the seabed. Because the jacket legs act as a template for the pile installation, these structures are sometimes call "standard template structures". Sometimes, in more severe environments, one pile through each of the main legs does not provide enough foundation support. Therefore, additional piles are installed around the bottom perimeter of the jacket between the main legs. These piles are called skirt piles and the foundation is termed the "extended skirt" type of foundation. An example of a traditional piled template structure with an extended skirt foundation is shown in Figure 7-2.

TABLE 7-1

OFFSHORE PLATFORMS: STATE-OF-THE-ART

Conventional Fixed Platforms	Operator/Field	Mate r Depth	Installation Date
Gulf of Mexico (3 piece Installation)	Shell Cognac	313 m/ 1025 ft	1978
Santa Barbara Channel (2 piece Installation)	Exxon Hondo	260 m/ 850 ft	1976
Gulf of. Mexico (Deepest Single Piece Conventional Jacket)	Union Cerveza	285 m/ 935 ft	1981
North Sea (Cluster Piles)	Conoco's Murchison	153 m/ 500 ft	J 980
Self-Floating Towers			
North Sea	B.P.'s Magnus	188 m/ 618 ft	1982
Offshore New Zealand	Shell /B. P./ Todd Maui	108 m/ 354 ft	1976
Guved Tower			
Gulf of Mexico	Exxon's Lena	305 m/ 1000 ft	1983
Tension Leg Pl atform (TLP)			
North Sea	Conoco's Hutton	147 m/ 482 ft	1984*

* Estimated Date

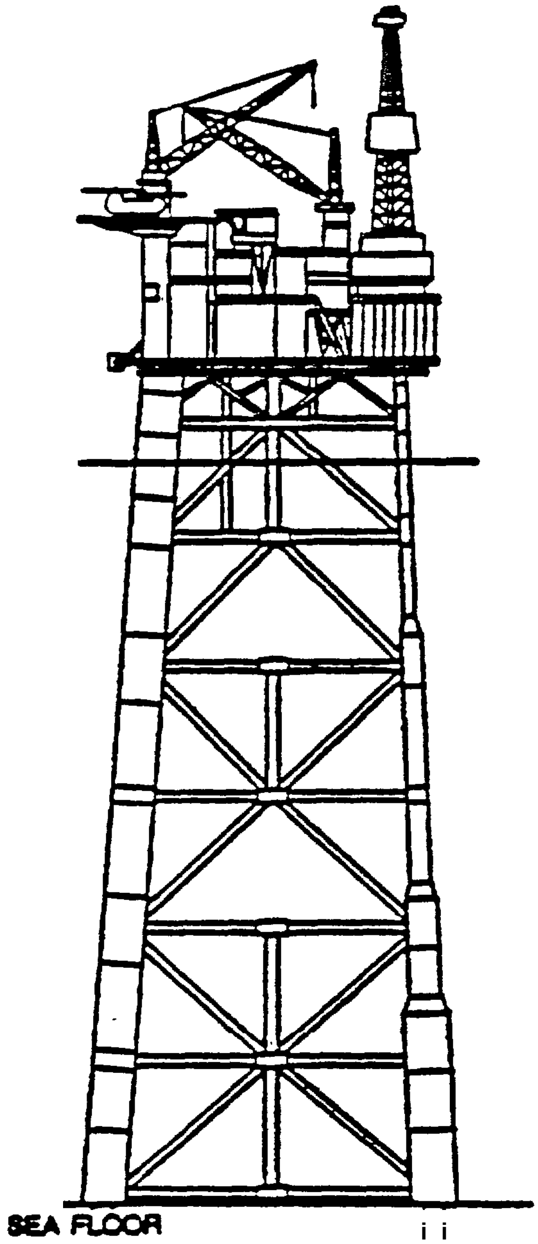


ELEMENTS OF A STEEL JACKET STRUCTURE

FIGURE 7-2

7.2.2 Self-floating Towers

Besides categorizing jackets according to the type of foundation, they are also classified according to the method of transportation and installation. Traditionally, jackets have been loaded onto barges at the fabrication site and transported by barge to the offshore location where they were skidded off the barge or "launched" into the sea. However, in early 1969 for the Maui field off New Zealand, it was determined that the size of barges available at the time would not provide sufficient stability during tow (Ref. 3). Therefore, it was decided to increase the buoyancy of the structure by increasing the size of two legs on one side to allow the structure to float on its own and be towed directly to the offshore location without the need for a launch barge. Thus, the term "self-floater" as shown in Figure 7-3 came into use. Since the Maui self-floater, there have been several others built for North Sea fields. In fact, the necessity of having large legs to house conductors in structures installed in Cook Inlet, Alaska, in the mid-1960's in order to protect the wells from ice floes, contributed to the use of a few self-floaters in that region even before the Maui structure was built. Because the large legs of the self-floater allow the designer to decrease the leg batter, the self-floaters tend to become more slender geometrically than conventional jackets. Therefore, the term "tower" is commonly applied to self-floater structures to reflect their relatively slender dimensions. In summary, due to the different modes of transportation just described, fixed space frame structures are often categorized as being either a "barge-launched jacket" or a "self-floater tower".



SELF-FLOATING TOWER

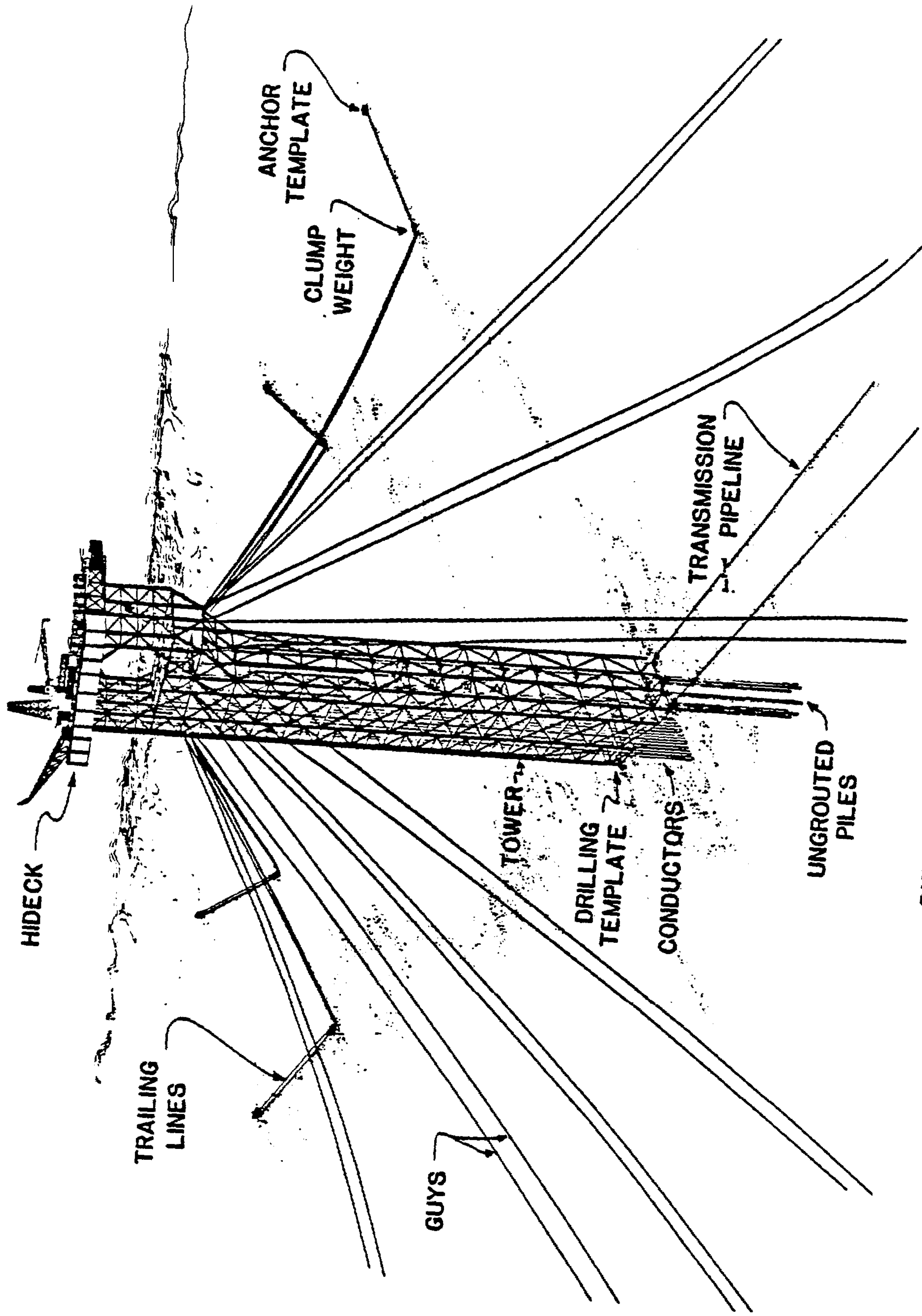
FIGURE 7-3

7.2.3 Guyed Towers

Although the guyed tower concept has been studied for many years, the first prototype was installed in 1983. This tower, Exxon's "Lena" platform, was located in 305 meters (1,000 ft) of water in the Gulf of Mexico. For this study, all cost estimates were based on information derived from this project. In addition to the Lena Project, design studies have been performed for towers in greater water depths (Ref. 43). Material from these studies has been extrapolated to cover a range of water depths from 305 to 610 meters (1,000 to 2,000 ft). Fabrication techniques closely resembling those for conventional fixed platforms can be used for the bulk of the guyed tower structure. Buoyancy tanks are included to support a portion of the deck weight, or payload, and will require special stiffened cylindrical shell fabrication procedures similar to those for the buoyant legs on the self-floating structures. Installation procedures are similar to setting a conventional jacket. However, the final location and orientation of the structure is more critical for a guyed tower because of alignment tolerances between the tower and the mooring system. Also, towers in deeper water may have to be fabricated and installed in two pieces. The water depth at which this will be necessary will depend upon the size of launch barges existing at the time of installation. For the purposes of this study it was assumed that launch barges capable of handling guyed towers in water depths up to 610 meters (2,000 ft) do exist and their anticipated lump sum rental rate has been estimated based on previous in-house analyses of ultra-launch barge economics. Figure 7-4 shows the typical guyed tower and identifies the major components.

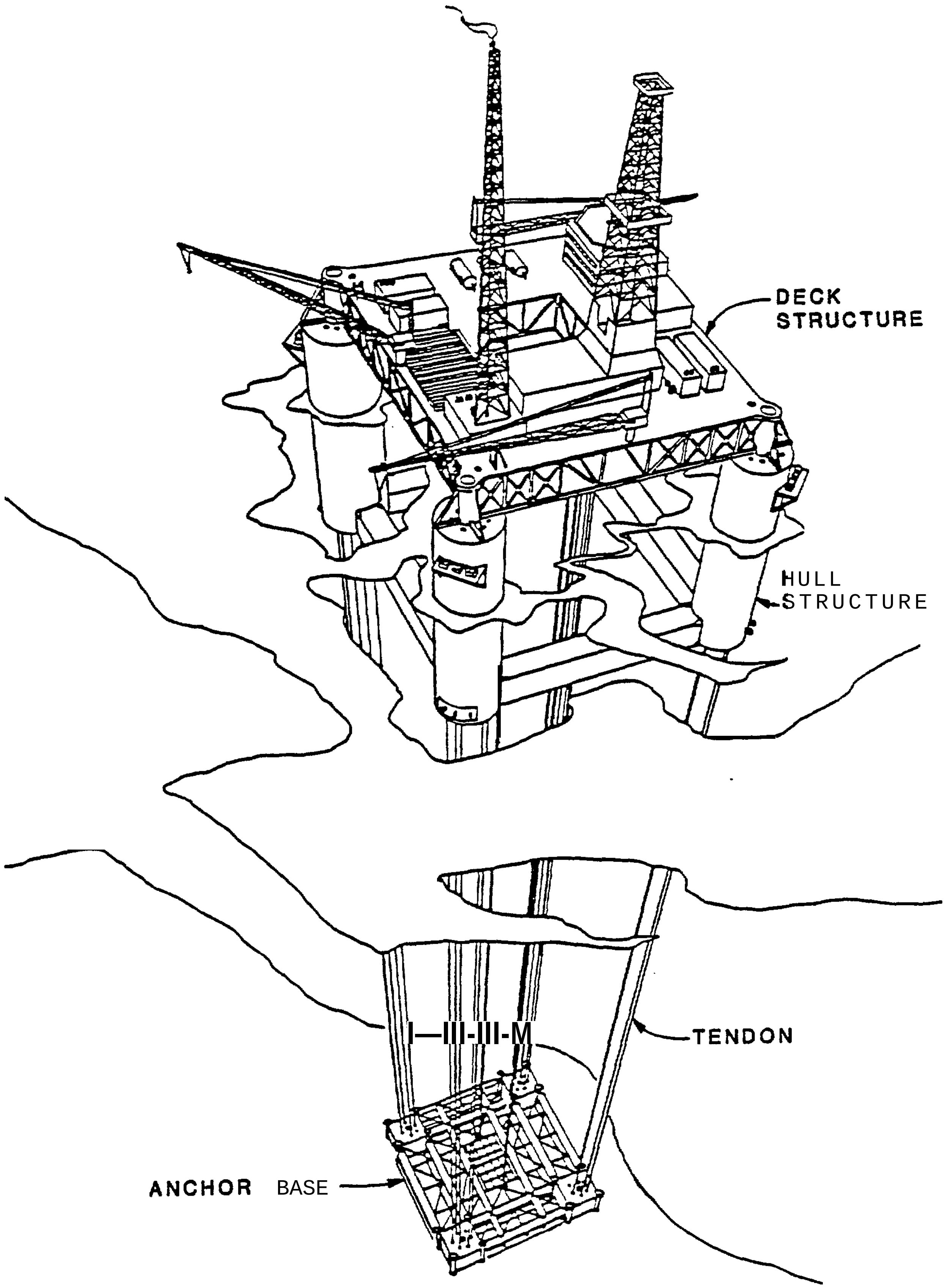
7.2.4 Tension Leg Platforms

The tension leg platform (TLP) is a floating structure, consisting of a hull and a deck, which is connected to anchors fixed in the seabed by vertical mooring legs called tension legs. Figure 7-5 depicts the major components that comprise a TLP.



GUYED TOWER COMPONENTS

FIGURE 7-4



TENSION LEG PLATFORM CONFIGURATION

FIGURE 7-5

The tension legs virtually eliminate the vertical plane motions of heave, pitch, and roll while the lateral movements in surge, sway and yaw are "compliantly restrained". In the early days of the TLP conceptual development, most drillers and oil and gas production engineers considered the TLP as a logical extension of semi-submersible rigs. Accordingly, conceptual systems were developed on the basis of the existing semisubmersible design technology. However, these production personnel soon discovered that, while a TLP is indeed highly compliant in the surge, sway, and yaw directions (periods of over 100 seconds), it is virtually fixed against pitch, roll and heave motions (periods of less than 5 seconds). These motion Restrictions result in fundamental differences between a TLP and a semisubmersible platform. In the case of the semi submersible, the prime objective is to minimize heave motions, while the TLP's members are sized to reduce variations in vertical anchor line forces (Ref. 44). The first TLP in the industry is scheduled to be installed in 150 meters (485 ft) of water in the Hutton Field of the North Sea in late 1984. This is a prototype structure. Actual applicability of the TLP will be in much deeper waters - probably beyond 450 meters (1 500 ft).

Buoyancy is provided by the hull which consists of vertical columns and horizontal pontoons. The columns and pontoons are essentially stiffened thin shells. An excess of buoyancy greater than the platform weight keeps the mooring lines in tension for all weather and all loading conditions. Column height is sufficient to support the deck above the wave crest elevations for all tide and wave conditions when the TLP is fixed to the seabed foundations by the tension legs.

The tension legs are also known as the tethers. The tethers will typically be connected at the corner columns in the hull and at the anchor templates on the seafloor. Tethers are one of the most critical elements of the TLP system. Various types of tethers such as steel wire bridge strand, Kevlar, high strength drill pipe and specially forged threaded high strength pipe joints have been proposed by the early TLP investigators. Kevlar is not favored at the present time because of the lack of satisfactory material information and field experience. Possible fatigue and corrosion problems discourage the use of the steel bridge strand. Though TLP's are relatively insensitive to water depth in comparison to fixed systems, tether weight may place an economic limit on the applicability of TLP's in deeper water, as briefly described in Section 7.3.5. The termination points of tethers at the TLP hull and the seabed anchor template undergo large rotations; fixed connections at these points would be subject to very high stresses. Therefore, methods for providing gimball action at the termination points have been studied by various researchers. These early efforts have resulted in elastomeric compression connectors. However, this is an area of ongoing research. Field experience with underwater long term behavior of elastomeric rubber materials subjected to cyclic shear and compression loadings is generally lacking. More field data and tests on these connectors are required to establish their long term reliability.

The drilling, production, and transportation riser system will face problems similar to those of the tether system. Much remains to be learned about the dynamic response of deep water risers to environmental and operational loadings.

The preferred method of anchoring the tether system to the seafloor at the present time is that of using a steel frame anchor template which is fixed in place by tension piles.

The ability to install the piling required to fix the seafloor anchor template in place has been made possible by recent advances in the development of hydraulic underwater hammers. The offshore industry is currently capable of driving large diameter piles in water depths beyond 305 meters (1,000 ft), possibly as deep as 460 meters (1,500 ft), using such hammers. Use of these hammers in deeper waters may require major design modifications.

Reliable design of tension piles under cyclic tensile loading is an area that is still under development and which requires further research. Present indications are that the tensile cyclic load, depending on its intensity and frequency, may reduce the pile capacity to a level of about 70 to 80 percent of its ultimate static tensile strength. The combined effect of cyclic tension and lateral loads is yet another area which is not well understood. Until these questions are answered, the industry tendency is towards using higher safety factors (3 or more) which increase cost. More testing work and actual field data may eventually decrease these factors of safety (Ref. 54).

One significant advantage of the TLP is that it may be possible to transport and install a TLP hull, deck and facilities as a single piece. This may provide the option of moving the platform to a different site after a field is depleted. Currently, the favored approach for deck installation involves fabricating the hull and the deck with its facilities as two separate pieces in two fabrication yards and then towing and mating the two pieces in a protected deep water location near shore.

7.2.5 Floating Production Systems (FPS)

The floating production system (FPS) is currently an attractive option for producing marginal fields and is one of the apparent economic alternatives to bottom founded structures for production in extremely deep water.

A sampling of current FPS installations is presented in Table 7-2. These systems are based on the use of converted semi-submersible drilling rigs and crude tankers. Subsea wells drilled from separate units produce through a flexible or rigid riser into process facilities on the floating unit as depicted in Figures 7-6 and 7-7.

The tanker system also contains storage and loading capability for export. The semi-submersible based systems lack storage and so they send the processed production back through the riser to a remote captive storage tanker for export. Well workover usually requires a separate vessel for the tanker based system and for remote satellites. Wells located directly under the FPS can be reworked from the semi-submersible.

The major advantages of the converted semisubmersible system are that:

A system to provide 60,000 to 75,000 BOPD which, except for the single-point storage tanker mooring, could be installed in water depths of 305 meters (1,000 ft) or more in a rough weather area using available and proven equipment and procedures.

The system would cost less than other comparable systems being considered.

Its major disadvantages are that:

The system is limited to production rates of less than 100,000 BPD of oil and to water depths in the range of 305 meters (1,000 ft).

The system will experience some weather downtime, due to tanker loading restrictions

Major workover of wells located directly beneath the semisubmersible will probably require shut-down of production.

TABLE 7-2

CURRENT FPS INSTALLATIONS

FIELD NAME	ARGYLL	BUCHAN	CASABLANCA	DORADA	ENCHOVA
LOCATION	North Sea	North Sea	Spain	Spain	Brazil
WATER DEPTH (m/ft)	80/260	122/400	122/400	9 5/31 0	190/620
CONFIGURATION	Anchored over Template	Anchored over Manifold	Anchored over Individual Wells	Anchored over Individual Wells	Anchored over Template
PRODUCTION RATE (M. B.O. p. D.)	70	72	25	20	60
RISERS	Rigid Non-Integral Integral	Rigid Non-Integral Integral	Catena ry	Individ. Tensioned	Flexible with Loop on sea floor
NUMBER/TYPE OF WELLS	7 Satellites	4 Sattelite 4 Template	2 2	3-4 3-4	4 Satellite 6 Template
STORAGE (1000 bbls)	0	3.5 (not used)	0	0	0
EXPORT BY	Shuttle Tanker via S.P.M.	Shuttle Tanker via S.P.M.	Pipeline	Pipeline	Shuttle Tanker via S.P.M.
DATES OF PRODUCTION	1976 to Present	1981 to Present	1977-1982 Replaced by Permanent Structure)	1978-1983	1978 to Present
FIELD DEVELOPMENT COST (MILLIONS OF US$)	70	285	N.A.	N.A.	66
OPERATING COST (THOUSANDS OF US$/DAY)	100	110	N.A.	35	100
LEAD TIME - START DESIGN TO FIRS PRODUCTION (MONTHS)	28	50	N.A.	N.A.	24

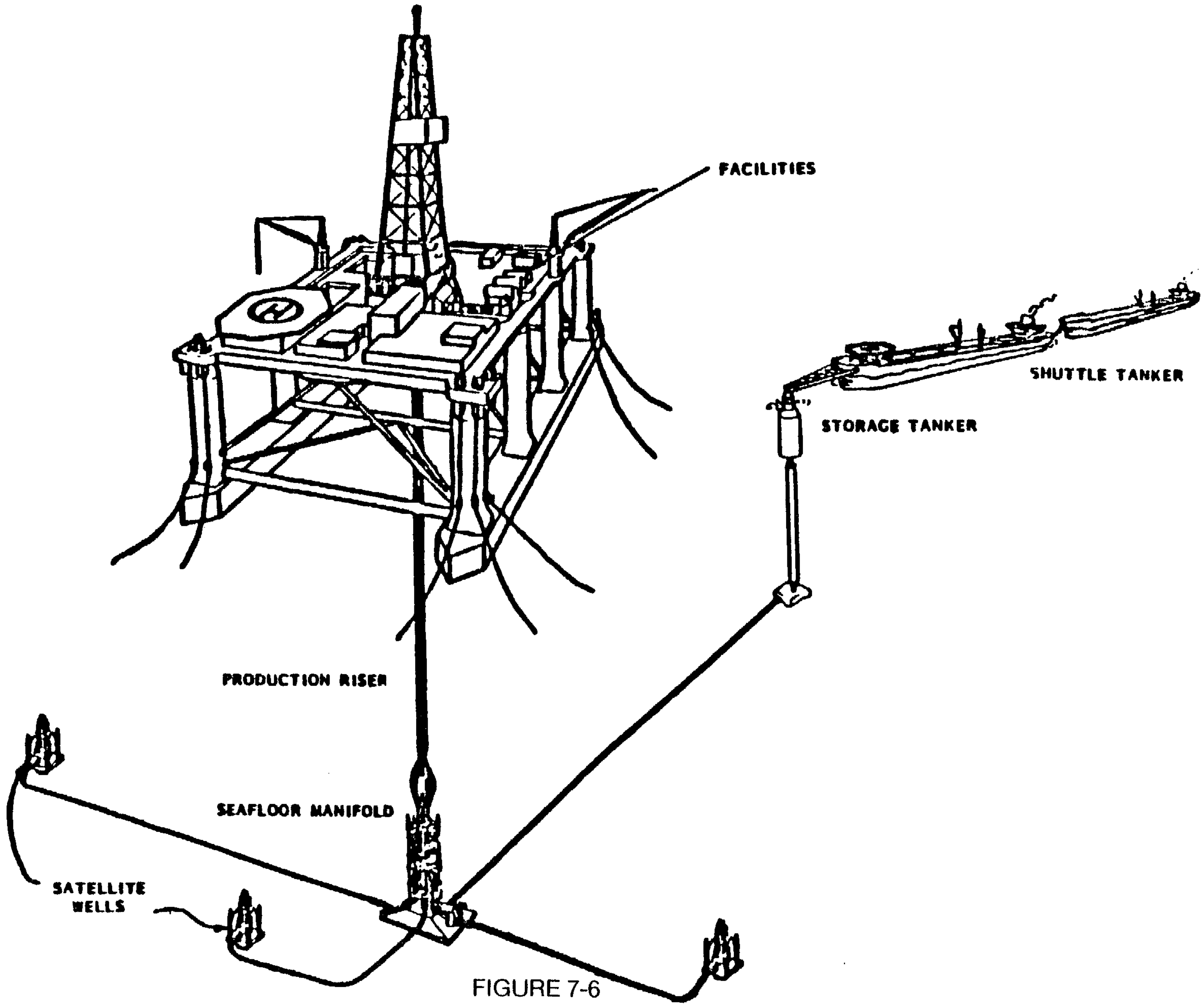
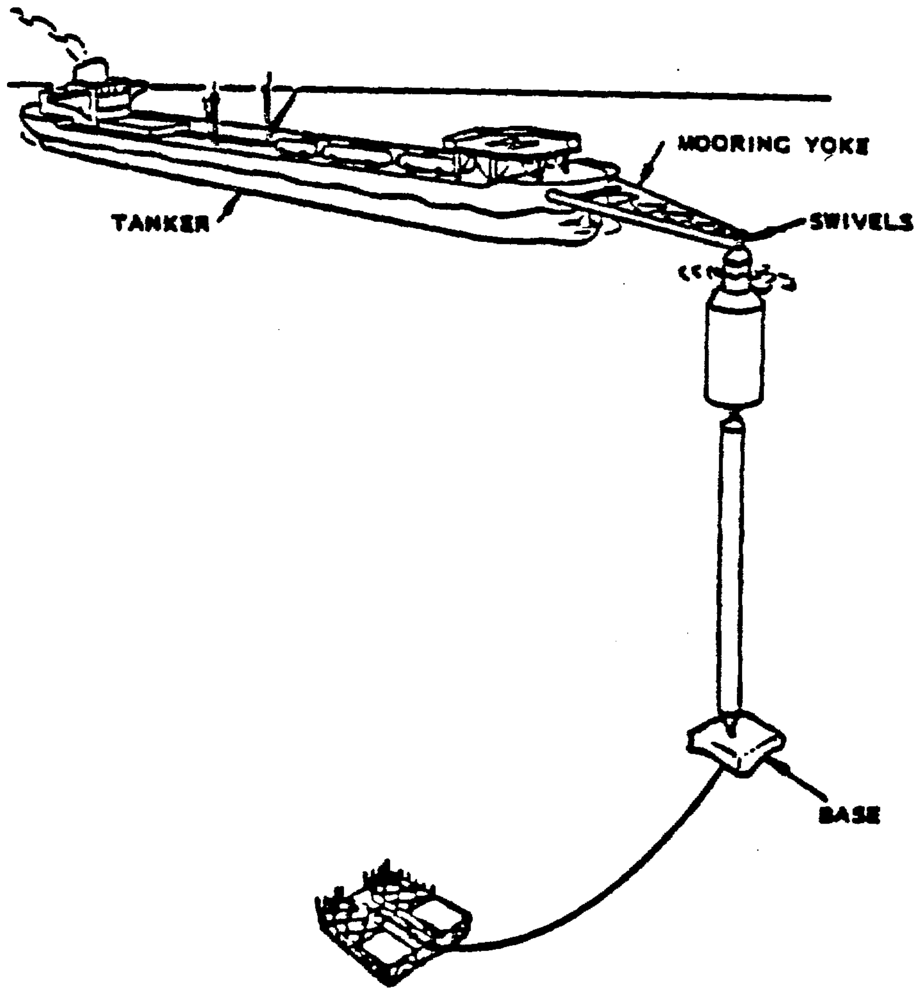


FIGURE 7-6

SEMI SUBMERSIBLE PRODUCTION YST M (CONVERSION)



TANKER BASEI) PRODUCTION/STORAGE SYSTEM WITH S. A. L. M.*

FIGURE 7-7

SINGLE ANCHOR LEG MOORING

The major advantages of a tanker system are that:

All production, storage, and unloading of oil can be done from one floating vessel.

The system is inexpensive in comparison with other systems, and major equipment has a high reuse factor.

Its major disadvantages are that:

The system will suffer weather downtime during severe weather.

Wells must be worked over from a separate rig.

Production capacity and well injection capability are limited by swivel & 'U' joint technology.

For small field development, conversion of tankers and drilling semi-submersibles are acceptable solutions although some compromises in throughput, efficiency and shutdowns due to weather can be expected. For harsh environments, semi-submersible units will probably be preferred due to superior motion characteristics and consequently minimized weather shutdown percentages. For production rates above about 70,000 BOPD, purpose built units will be required. If tanker transport is planned, integral oil storage should be incorporated in the semi-submersible design to allow production to be maintained when weather conditions are too severe for tanker loading to continue. A purpose built monohull would be less expensive to construct but less efficient in terms of operating output and overall throughput capacity. Both concepts can be ice strengthened to cope with conditions in the deep water portions of the Bering Sea. Section 7.5.4 documents projected costs for future large scale purpose built semi-submersible and monohull production systems in sub-arctic regions.

7.3 Influencing Factors for Sub-Arctic, Deep Water Support Structures

The major influencing factors which will be controlling the supporting structure for drilling and production platforms in sub-arctic regions include: water depth, static wave forces, dynamic wave amplification, associated fatigue problems, sea ice, seismic effects, unstable seabed conditions and low soil strengths, topside loads and construction methods.

7.3.1 Dynamic Wave Amplification

support structures for the topside drilling and production facilities are usually classified according to their type of foundation support, i.e., bottom-founded or floating. However, in deeper waters, a different scheme of classification based on the dynamic characteristics of the structure may be more appropriate. The reason for this is that, as the ratio of the natural period of the platform to the period associated with the significant energy in the design sea state grows closer to unity, inertial forces become important. Accordingly, static methods of analysis are no longer adequate, and dynamic application of the wave loadings must be considered. Not only are the member forces amplified but the range of cyclic stresses in the members is also amplified, thereby making fatigue a more significant design consideration.

Ultimately, the problem of dymamic amplification in deep water is dealt with by utilizing a more compliant structure than the traditional piled space frame. A compliant structure is more flexible - i.e., it tends to move with the waves. Such flexibility increases the structure's natural period to a level greater than the period associated with significant energy in the design sea state. This phenomenon decreases the tendency of the structure to resonate with the exciting wave forces. In fact, when the ratio of the structure's fundamental natural periods to the predominant wave period becomes large enough, dynamic deamplification of the static forces can occur because the inertial forces will tend to act in a sense opposite to the wave forces. The above concept is graphically illustrated in Figure 7-8, where the dynamic behavior of structures has been divided into four regions (Ref. 44). In region I, the amplification of the wave forces is negligible. Shallow water platforms fall into this category. The natural period of the platform must be less than about twenty percent of the design wave period so that the wave forces can be assumed to act in a static manner. Region 11 is characterized by dynamic amplification. Deepwater fixed platforms fall under this region. The upper limit of this region is governed by a number of factors including fatigue, practical design and construction considerations and platform cost. At the present state of the art, the platform natural period can usually be as high as forty to fifty percent of the period of the design wave before the amplified forces become too great to permit an economically viable platform. Region 111 is characterized by high dynamic amplifications. Economic considerations preclude the design and construction of structures having fundamental natural periods that fall within this region. Compliant structures such as a guyed tower, buoyant tower, tension leg platform or semi-submersible belong to region IV.

Figure 7-9a is another concise way of showing the relationship between the natural sway periods of fixed and compliant structures and the predominant wave periods of typical storm sea states (Ref. 2). The designer attempts to minimize the sway period of fixed structures so as to remain on the short-period side of the wave energy spectra, while with compliant systems, these sway periods are maximized to negate or minimize the effects of the exciting wave spectra.

In summary, deepwater structures can also be classified according to their dynamic response characteristics. As a result, all such structures can be divided into the following two (2) categories:

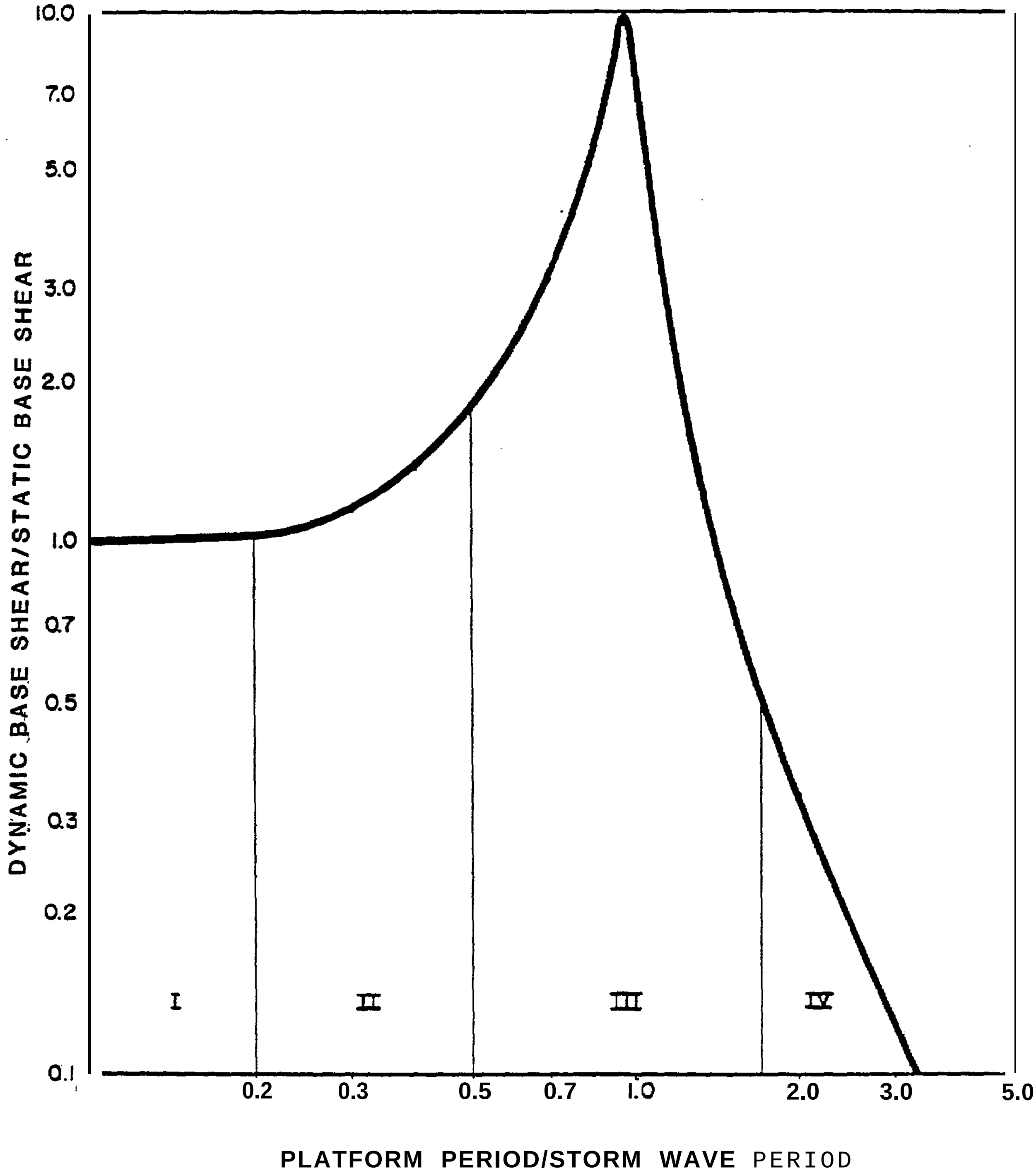
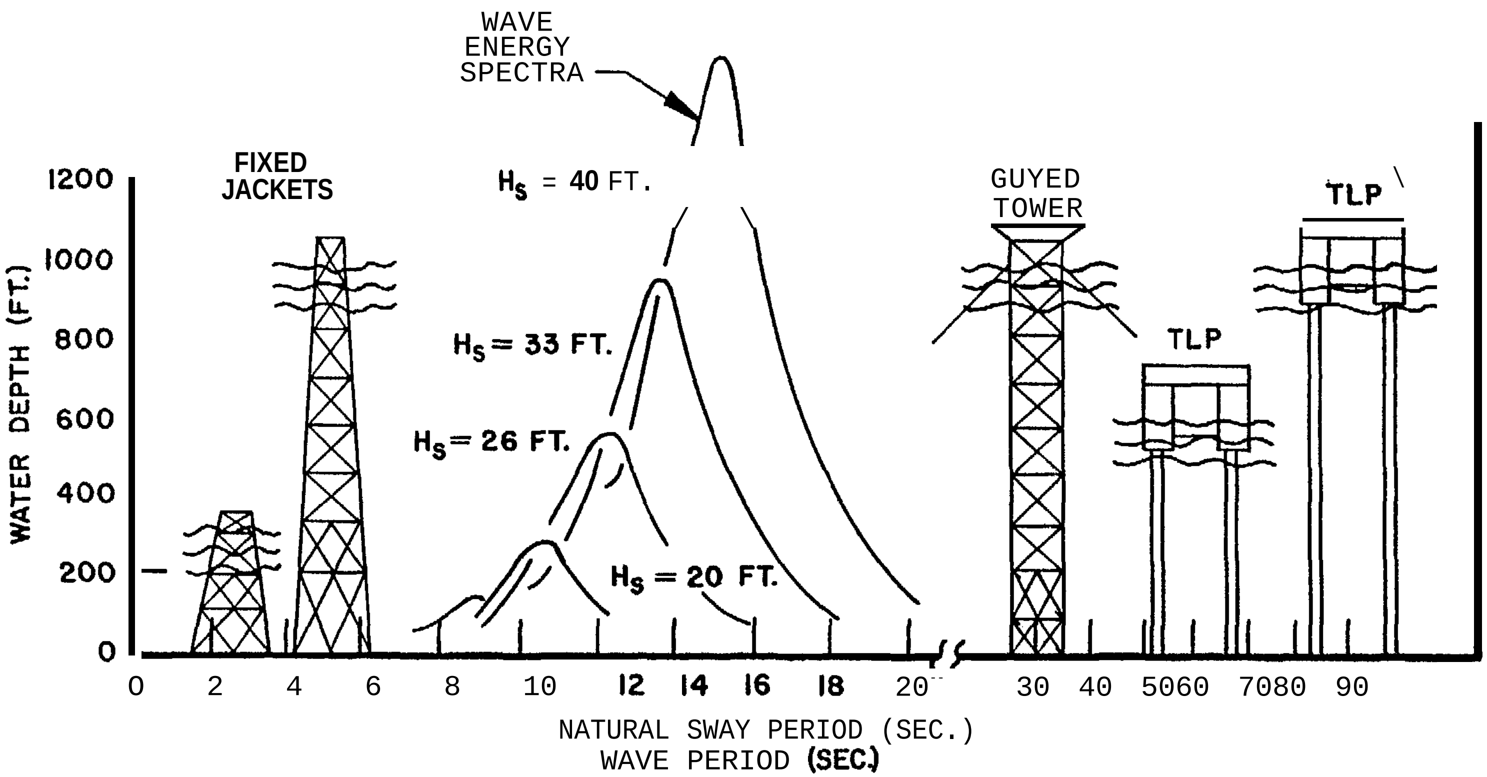


FIGURE 7-8

WAVE RESPONSE SPECTRUM



PLATFORM NATURAL SWAY PERIOD

RELATIVE TO SEA-STATE ENERGY

FIGURE 7-9a

- those structures whose fundamental natural periods are shorter than the predominant wave periods - primarily fixed structures, such as the traditional piled jackets and gravity base structures.

- those structures whose fundamental natural periods are longer than the predominant wave periods - primarily compliant Structures, such as the guyed tower, the buoyant tower, the tension leg platform, and the semi-submersible.

7.3.2 Sea Ice

Sea ice can be encountered in the Bering Sea and can occur in sizes ranging from extensive sheets over 1.0 meter thick to small broken pieces. In any case, significant damage can be expected on unstrengthened platform elements that pierce the water surface such as structural bracing, well conductors, pipeline risers and pump tubes. In the Navarin and St. George Basins, these appurtenances will require protection similar to the approach taken in Cook Inlet where wells were grouped inside one or more large diameter legs. Other components may be protected inside a large diameter caission that extends through the zone where damage could occur. The TLP and floating production systems may be protected by grouping these elements inside the large buoyancy columns.

The use of a few large diameter columns also serves to minimize ice forces on the structure by eliminating the need for conventional horizontal and diagonal framing in the vicinity of the waterline. Sea ice loads on the order of 100 kips/foot and 70 kips/foot of structure interaction width have been assumed for the Navarin and St. George Basins, respectively, as discussed in Sections 4.0 and 5.0.

7.3.3 Seismic Loads

Seismic load intensity decreases from south to north in the study area. The extreme case occurs in the Gulf of Alaska where the API classifications of Seismic Zones 4 and 5, with the associated peak horizontal ground accelerations of 0.259 and 0.40g, respectively, have been applied. St. George and Navarin Basins are classified as API Zones 3 and 1, respectively, with associated peak horizontal ground accelerations of 0.20g and 0.05g.

Seismic loads on piled or gravity base structures impose increased strength requirements resulting in greater structural tonnage and more extensive foundation designs. The compliant guyed tower, TLP and floating systems require increased foundation requirements. Pipelines will also require special consideration in these seismic zones. Seabed conditions in terms of liquefaction and slope instability impose additional loads on a structure as a direct effect of seismic activity as discussed in Section 7.3.4.

7.3.4 Seabed Conditions

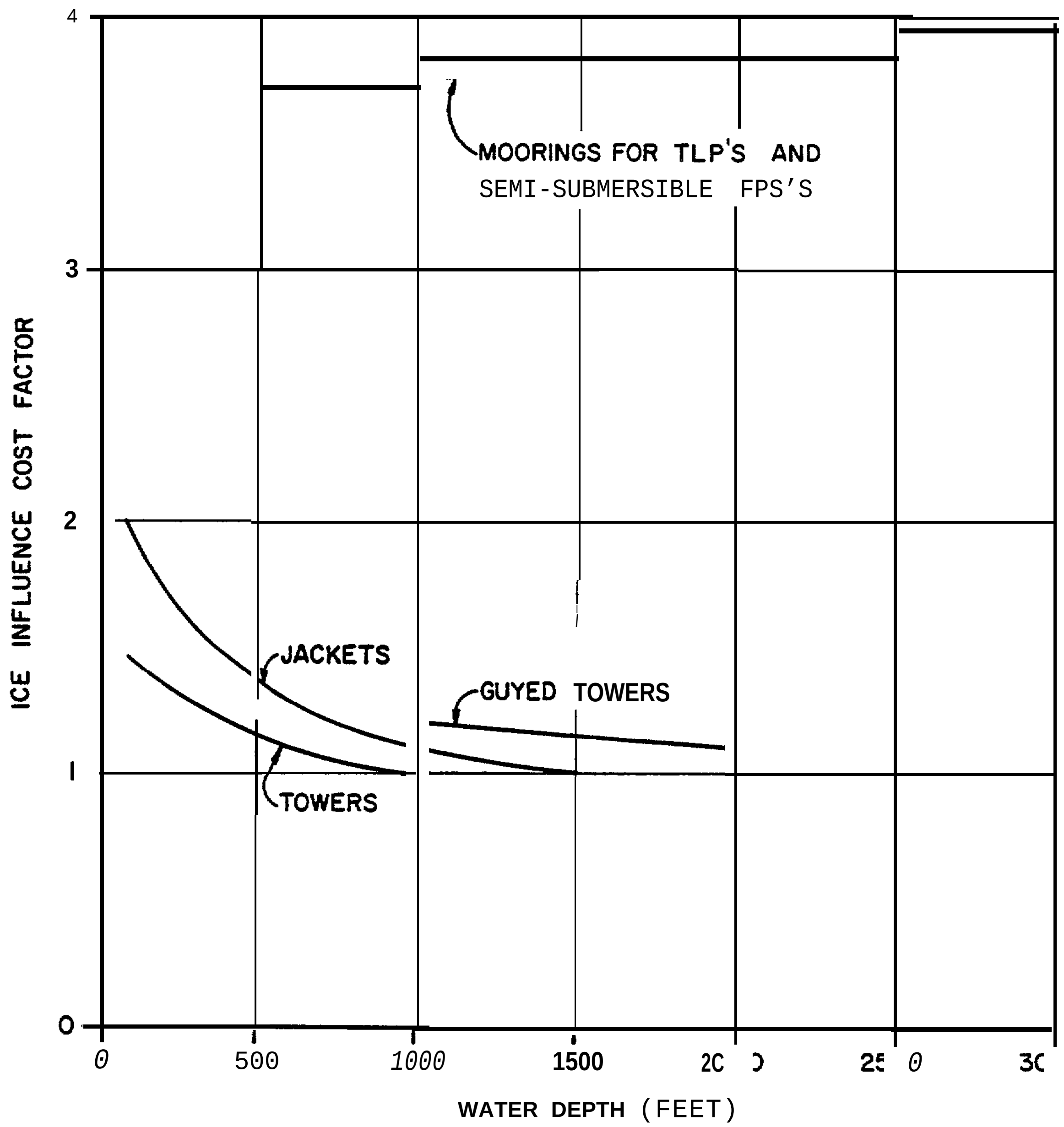
Beyond the 200-meter contour, the seafloor gradient and slope stability will be of primary importance in the selection and design of production systems, including platforms and pipelines. The steep seafloor gradients and questionable slope stabilities which characterize each of the study regions to varying degrees tend to preclude the use of gravity base structures due to the inherent requirement of such structures for a level seabed that exhibits greater foundation strengths than are expected in any of the study regions. A hybrid structure utilizing gravity and piles may be applicable but data was too limited to assess this configuration.

Seabed slopes ranging from about 2-8 degrees off horizontal, and various degrees of unstable, unconsolidated or poorly consolidated seabed soils are documented in all regions. The further inclusion of seismic activity can cause soil liquefaction and mudslides. Site specific seabed surveys will hopefully locate more favorable areas for locating permanent development components to minimize the effects of these phenomena. Piled structures have been successfully utilized on sloping, soft seabeds; however adequate environmental data and foundation information are necessary to establish the design parameters. It is expected that the guyed tower, TLP and floating units can be designed for these conditions, especially since their design inherently minimizes some of these effects.

Pipeline system designs will require detailed route surveys to avoid the mudslide prone areas. In addition, pipeline systems will have to be flexible to cope with the seabed movement that is often associated with the steep gradients and relatively weak soils along many portions of the continental slope.

7.3.5 Summary of Physical Environment Influences on Fixed Systems

Figure 7-9b summarizes the relative effects of ice influences on cosst factoring for the various deepwater structures and systems in the study regions. Seismic zone classification (API Zone 5) and the static and dynamic wave effects also have the great influence on structure weight. Because the global lateral load imposed by the storm wave and the design ice feature appear to be similar [in the worst case of Navarin Basin), the effects of the ice load over and above the wave effects are relatively smal 1. However, this statement must be tempered with the knowledge that only a tower-like fixed structure with very large diameter stiffened legs is considered feasible for the Navarin and St. George Basins and that such a structure is heavier than a conventional jacket would be in the same location if no ice existed,



GENERAL COST INFLUENCES DUE TO ICE

FIGURE 7-9 b

Depending on site-specific soil data, the relative effects of soils conditions could vary noticeably. However, the prime effect will be on the piling which is a relatively small contributor to total platform cost in deep water in comparison to that portion of the jacket or tower structure above mudline.

7.3.6 Topside Loads

As described in Section 8.0, topside loads for drilling and production facilities vary according to production rates, process, utilities, number of wells and drilling rigs, bulk storage capacity and other platform functions. As a general rule, the production facilities can be idealized in terms of production rate, plan area and dry weight. Two of those factors, area and weight, directly affect the size of the support structure.

For this study, three (3) production rates of 100,000, 150,000 and 200,000 BOPD have been investigated. The impact of production rate is reflected primarily in the fabricated tonnages of the support structure. The other associated costs for installation, design and certification are not significantly affected.

Superstructure icing loads are anticipated in all three study regions as discussed in Section 3.0. For the production rates assumed, the weight increase in total topsides load due to ice accretion is less than the increase due to 50,000 BOPD increments of production. Though it is negatively small, the ice accretion loading is reflected in the support structures tonnages and costs.

7.4 Summary of Support Structure Costs

Factors which influence the selection, design and cost of support structures have been discussed in previous Sections along with recent developments which substantiate the selection of viable concepts for deep water sub-arctic areas. Since the deep waters of the sub-arctic are still undeveloped, historical information from existing design work in the Gulf of Mexico and North Sea was used to estimate steel tonnages for cost estimating purposes. No structural design analysis work was performed specifically for the platform support structure in this study. A major influence on the size, weight and cost of support structures is the deck size requirement to support drilling and production facilities. In turn, higher production rates are required to justify the increased investments for structures in deep water. Using this approach the deck sizes generated for platform development in Section 8.0 were taken as the starting point for determining structure size and tonnage corresponding to a particular production rate in a "mild" Gulf of Mexico environment. Then, the physical environment influence factors, as described in Section 7.3, were applied to the base weight to arrive at final tonnages corresponding to our severe subarctic environment.

Construction costs are currently depressed because of a downturn in the offshore industry. Since it is impossible to predict the duration of this current situation, rates utilized in this study reflect a more normal market condition spanning recent years.

Fabrication rates were estimated for three categories; 1) conventional jacket framing - $3,200 per ton; 2) stiffened tubulars for buoyancy tanks, columns and hull sections for TLP and FPS - $4,200 per ton; and 3) piling -$1,200 per ton.

Installation costs were based on the use of a heavy lift, dynamically positioned, semi-submersible crane vessel, since conventional mooring methods in deep water may not be economically viable. Underwater hammers were assumed for pile installation.

Transportation of the large structures was based on seagoing types for the self-floating configurations and ultra-large cargo barges to carry the large single-piece conventional jackets and guyed tower structures. Two transport distances were considered; the U.S. West Coast and the Far East. Since fabrication cost was the dominating factor in total installed cost, the sensitivity to installation cost variables is minimal.

In performing the cost calculations, the approach taken was to form a "best estimate consistent with engineering and construction experience under normal conditions." Thus, there may be a bit of conservatism in selecting day rates and durations to make allowance for normally expected "weather downtime". Unforeseen occurrences of extreme weather conditions which might cause a delay to the next season are not included. The intent is that some normal contingency factors are included in the base costs contained herein in a manner deemed appropriate. An additional contingency factor of 30% to 50% is recommended for sensitivity assessment.

Bottom founded piled structures are economically feasible out to about the 300 meters (1000 ft) water depth contour. The compliant guyed tower begins to look attractive at around the 300 meter contour followed by the TLP and FPS in water depths greater than about 500 meters (1640 ft). This trend is generally true for all study regions as shown in Figures 7-10, 7-11, and 7-12.

7.5 Development of Support Structure Costs

The most widely used method of accommodating drilling, production and personnel for producing hydrocarbons offshore has been the fixed platform. This concept grew from the idea of providing lateral bracing for freestanding piles and reached its highest present development in Shell's Cognac, Exxon's Hondo and Union Oil's Cerveza platforms. However, a simple extension of early technology found

FIGURE 7-10

DEVELOPMENT PLATFORM COST

GULF OF ALASKA

COSTS INCLUDE: **PRODUCTION FACILITIES**
SUPPORT STRUCTURE
ENGR., FABR. a **INSTALLATION**

COSTS EXCLUDE: **DRILLING**
EXPORT *SYSTEM*
OPERATING **EXPENSE**

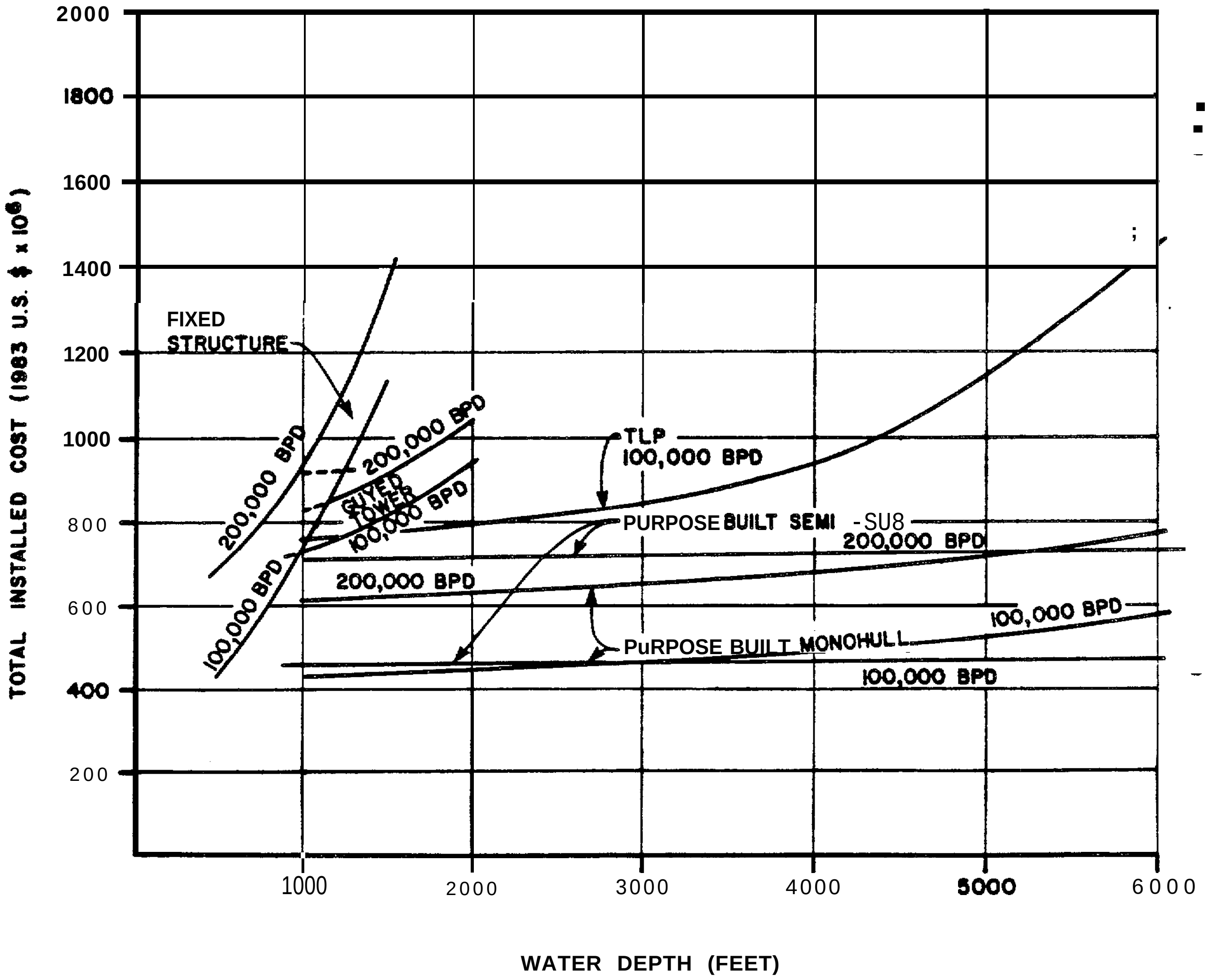


FIGURE 7-11

DEVELOPMENT PLATFORM COST

ST. GEORGE BASIN

COSTS INCLUDE : PRODUCTION FACILITIES
SUPPORT STRUCTURE
ENGR., FABR. & INSTALLATION

COSTS EXCLUDE : DRILLING
EXPORT SYSTEM
OPERATING EXPENSE

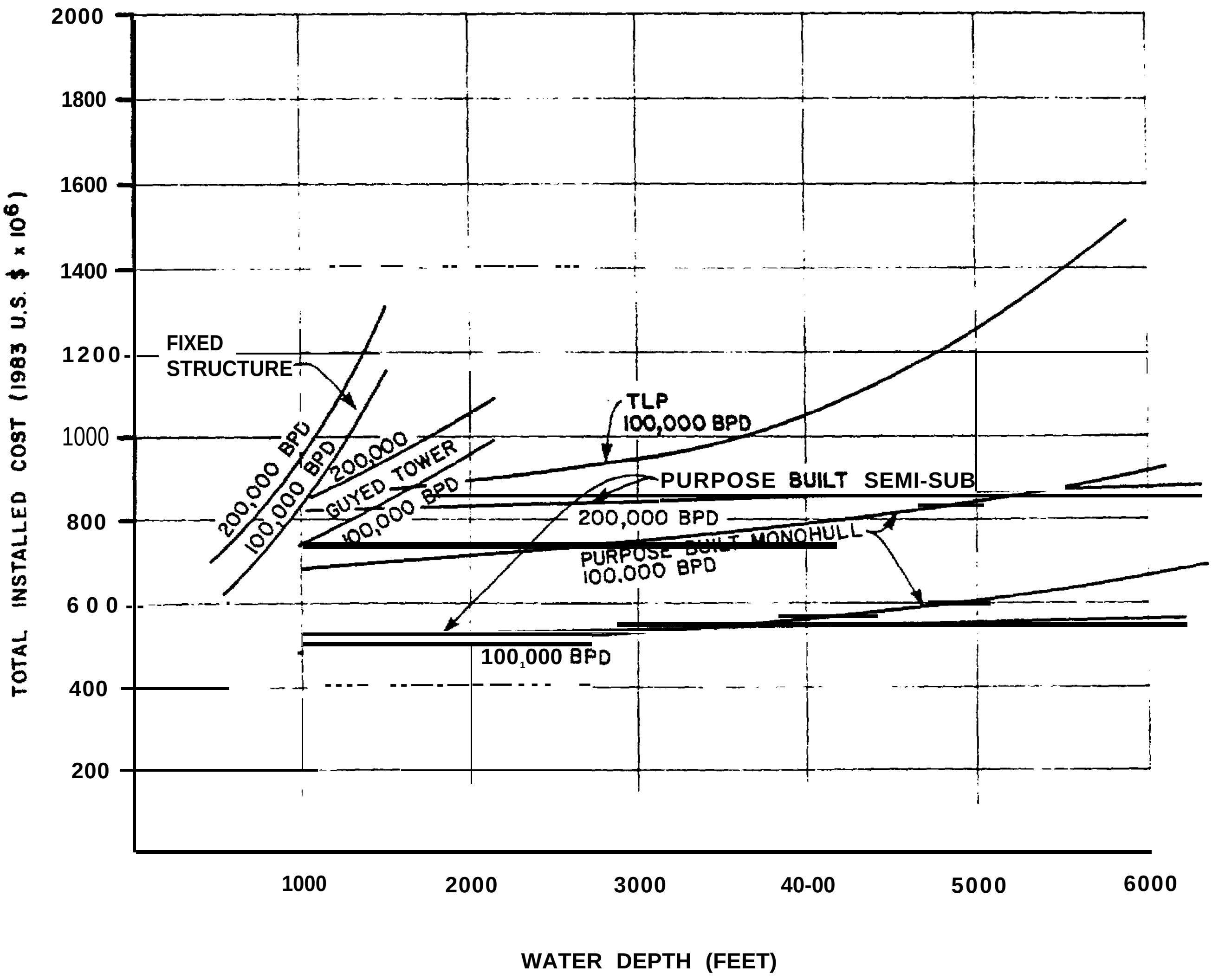


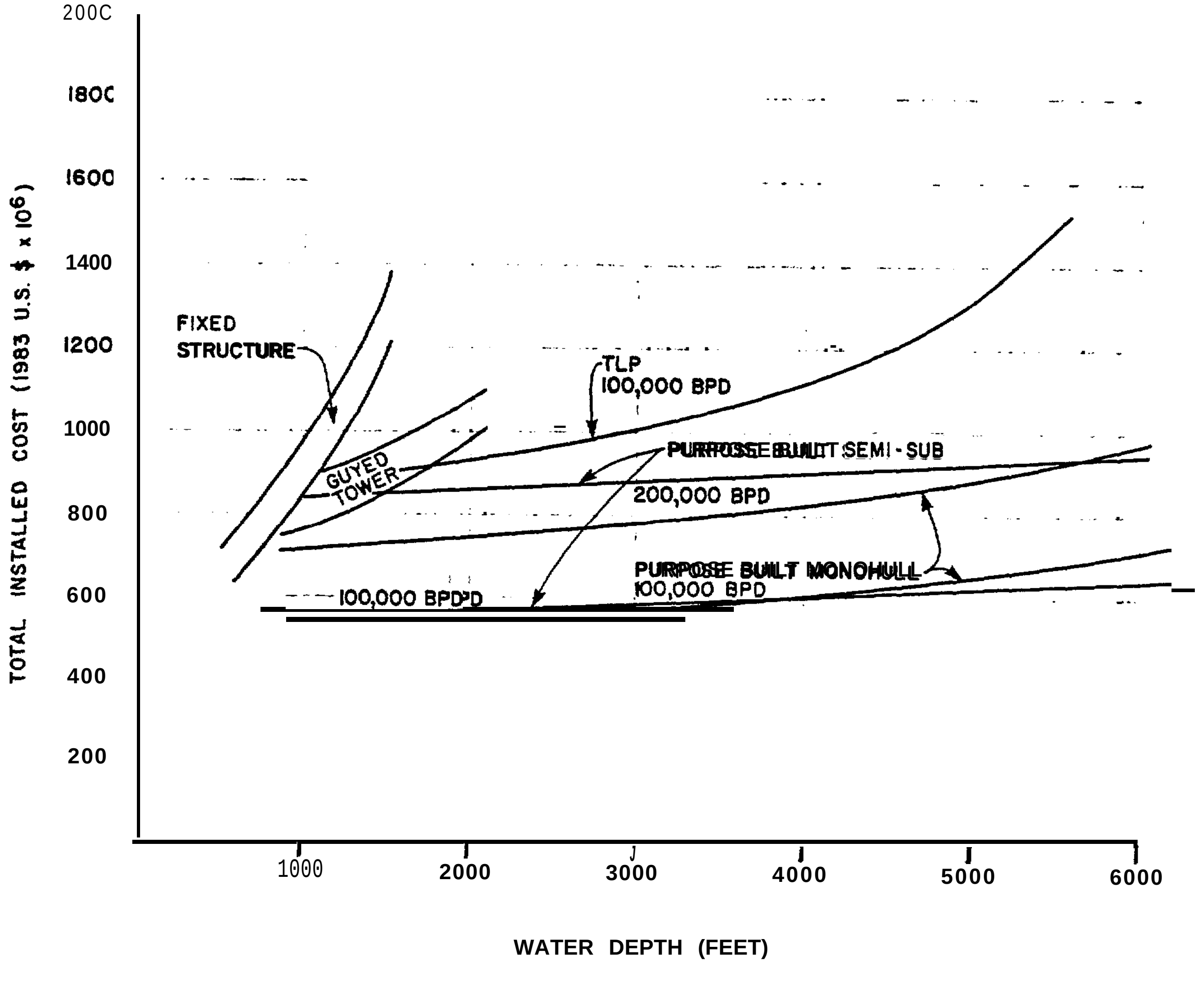
FIGURE 7-12

DEVELOPMENT PLATFORM COST

NAVARIN BASIN

COSTS INCLUDE: PRODUCTION FACILITIES
SUPPORT STRUCTURE
ENGR., FABR. & INSTALLATION

COSTS EXCLUDE: DRILLING
EXPORT SYSTEM
OPERATING EXPENSE



perfectly adequate in applications nearly four decades ago will not suffice for the deeper water currently deemed attractive by offshore operators. Tension leg platforms, guyed towers, semi-submersibles and other new structural concepts are proposed as alternatives to the fixed offshore platform. While these alternatives are being pursued and feedback will be available soon to the industry on their relative merits, efforts are underway to extend the waterdepth limits of conventional fixed platforms.

7.5.1 Conventional Fixed Platforms

Previous discussion in Section 7.2 described recent developments in fabrication and installation technology that are extending the range of water depths in which the conventional fixed platform appears to be technically feasible. Historical information from existing designs in the Gulf of Mexico and North Sea have proven existing technology up to 305 meters (1,000 ft), and Reference 21 indicates satisfactory in-place behavior of a conventional fixed platform can be achieved in water depths of up to 500 meters (1,650 ft.) depending upon location and environment.

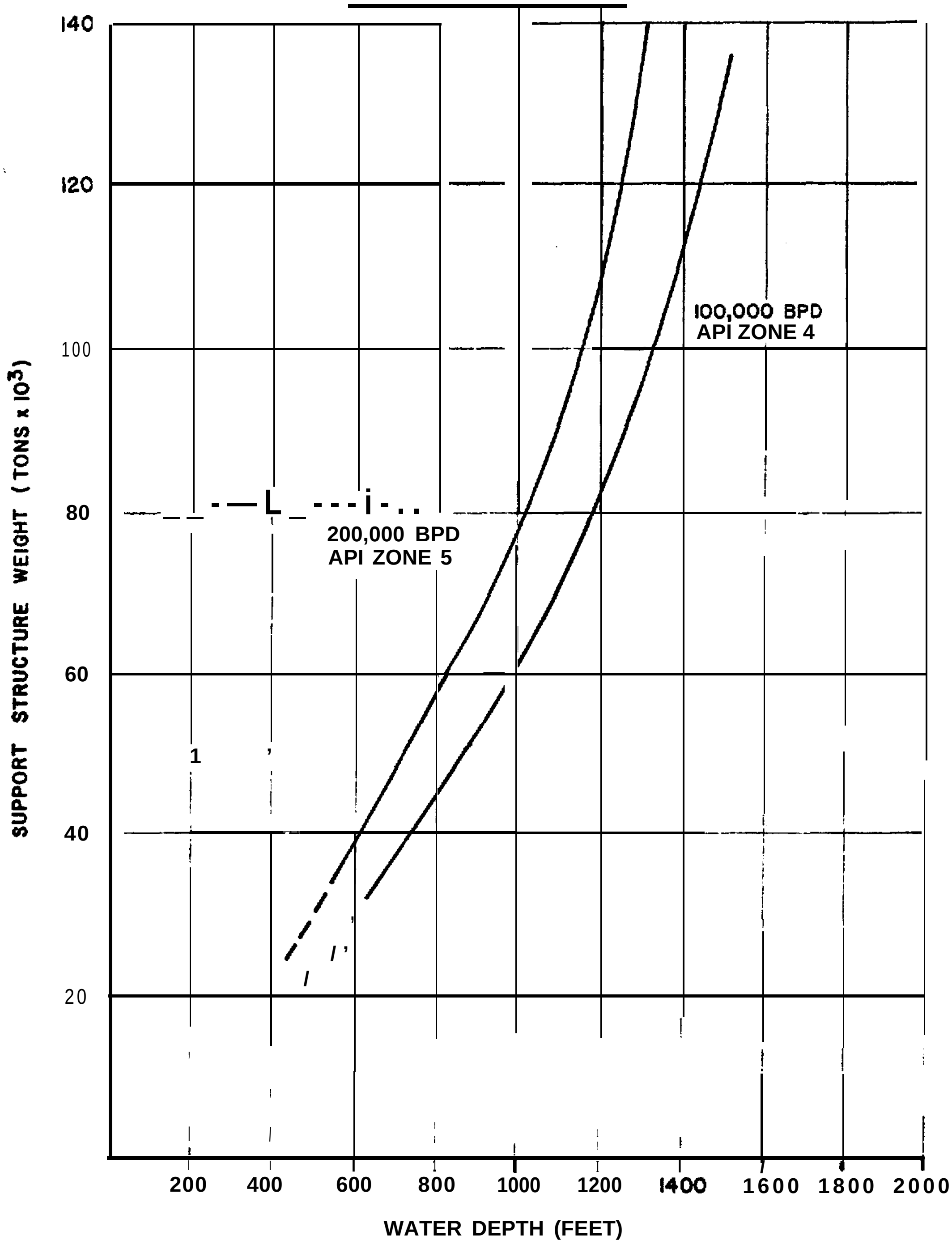
Because of their similar characteristics, both large launched and self-floater type structures are discussed in this Section. The basic cost constituent is structural steel tonnage. From available North Sea data the curves in Figure 7-13 were developed to represent the weight versus water depth relationship in the Gulf of Alaska for a harsh environment structure subject to seismic loads, fatigue and dynamic wave amplification. Seismic effects for API Zones 4 and 5 were estimated from in-house studies. Piling weight was estimated as a percentage of jacket/tower weight. "Weaker than typical" soil conditions were accounted for by increasing the percentage of jacket weight allocated to piling beyond historical averages representative of typical soil parameters. Unstable seabed conditions can be estimated by a assuming an artificial height of jacket structure to

FIGURE 7-13

CONVENTIONAL PILED STRUCTURE

WEIGHT VS. WATER DEPTH

GULF OF ALASKA



account for the depth of the potential mudslide, i.e. , a mudslide depth of 20 meters (65 ft) would result in selecting a structure weight corresponding to a water depth 20 meters deeper. The corresponding pile weights can again be estimated as a percentage of jacket weight, but the percentages are considerably greater than for non-slide conditions.

Sea ice conditions in the Bering Sea led to a decision to consider only self-floater (tower) type structures for the St. George and Navarin Basins. The inherent design of this concept provides the large diameter legs required to protect the well conductors and other platform appurtenances that pierce the water surface. Weight versus water depth relationships were produced as shown in Figure 7-14.

The estimated ice loads were found to be comparable to maximum wave loads in these regions and generated little additional weight over and above those generated by wave effects. Pile weight was determined from a percentage of jacket tower weight. Soft seabed conditions were considered by applying an additional weight factor to the piling in all regions and to the tower in Navarin Basin where the weakest soil conditions are anticipated. In all cases, fabrication costs became more significant and installation costs became less significant with increasing water depths as shown in Figure 7-15.

7.5.2 Guyed Towers

The guyed tower is a compliant structure and receives lateral support from the guylines; thus, there is no need for battered legs to resist overturning moment in the manner of a conventional fixed platform which cantilevers off the seaf100 r. The tower cross-section is essentially uniform along its length. Vertical loads in the tower are resisted by a piled foundation and several

FIGURE 7-14

SELF FLOATER TOWERS WEIGHT VS. WATER DEPTH

BERING **SEA**

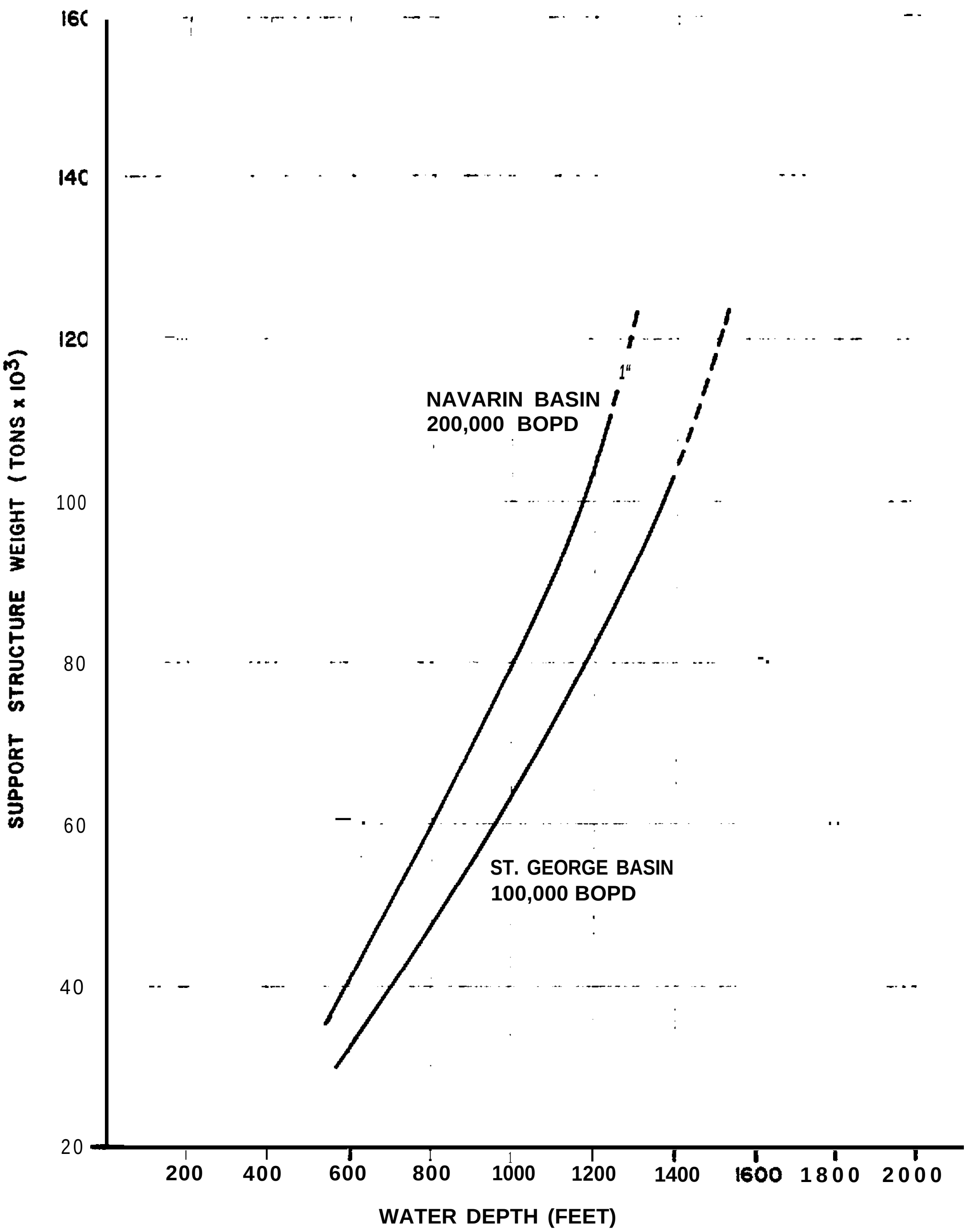
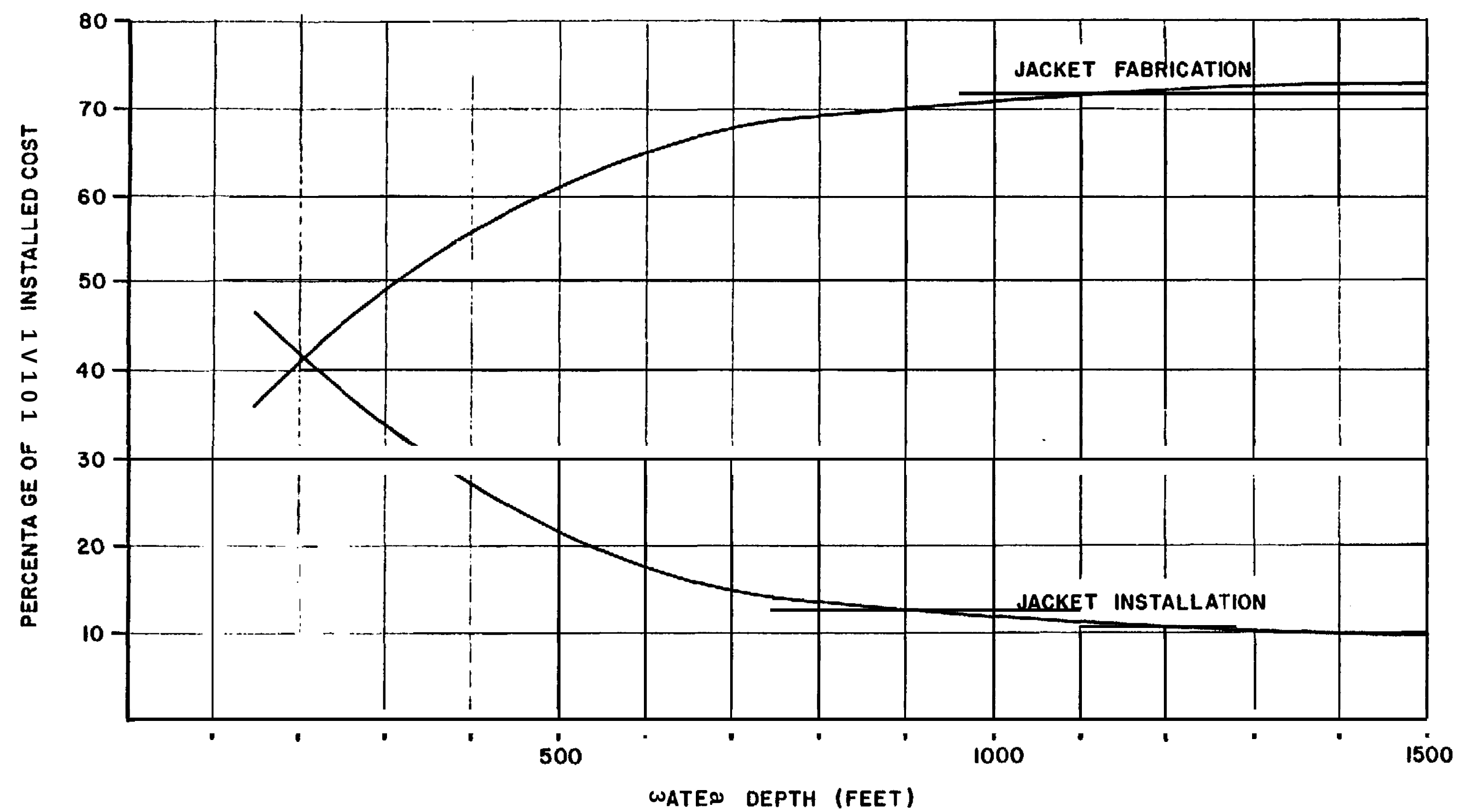


FIGURE 7-15

COMPONENTS OF LAUNCHED PLATFORM

TOTAL INSTALLED COST

TOPSIDES NOT INCLUDED)



NOTE: 17.5% OF TOTAL INSTALLED COST HAS BEEN ASSUMED FOR PROJECT MANAGEMENT, DESIGN, CERTIFICATION & CONSTRUCTION INSURANCE.

large buoyancy tanks. The foundation is composed of vertical piles clustered in the center of the platform. The central location of the piles allows the tower to tilt from the vertical at the mudline and to obtain the necessary compliant response to horizontal loads. The buoyancy tanks are located in the upper half of the tower to carry a portion of the deck gravity loads and reduce bending forces in the tower during the largest structural oscillations. In comparison with other conventional structure concepts, the other features unique to the guyed tower are the guylines, anchor piles, and clump weights.

Several in-house studies have been completed for guyed towers. These studies have included an assessment of their applicability over a range of water depths. From this data and the data available from the Lena guyed tower, an estimation of guyed tower structural tonnage was developed for the range of the water depths from 300 to 600 meters (1 ,000 to 2,000 ft).

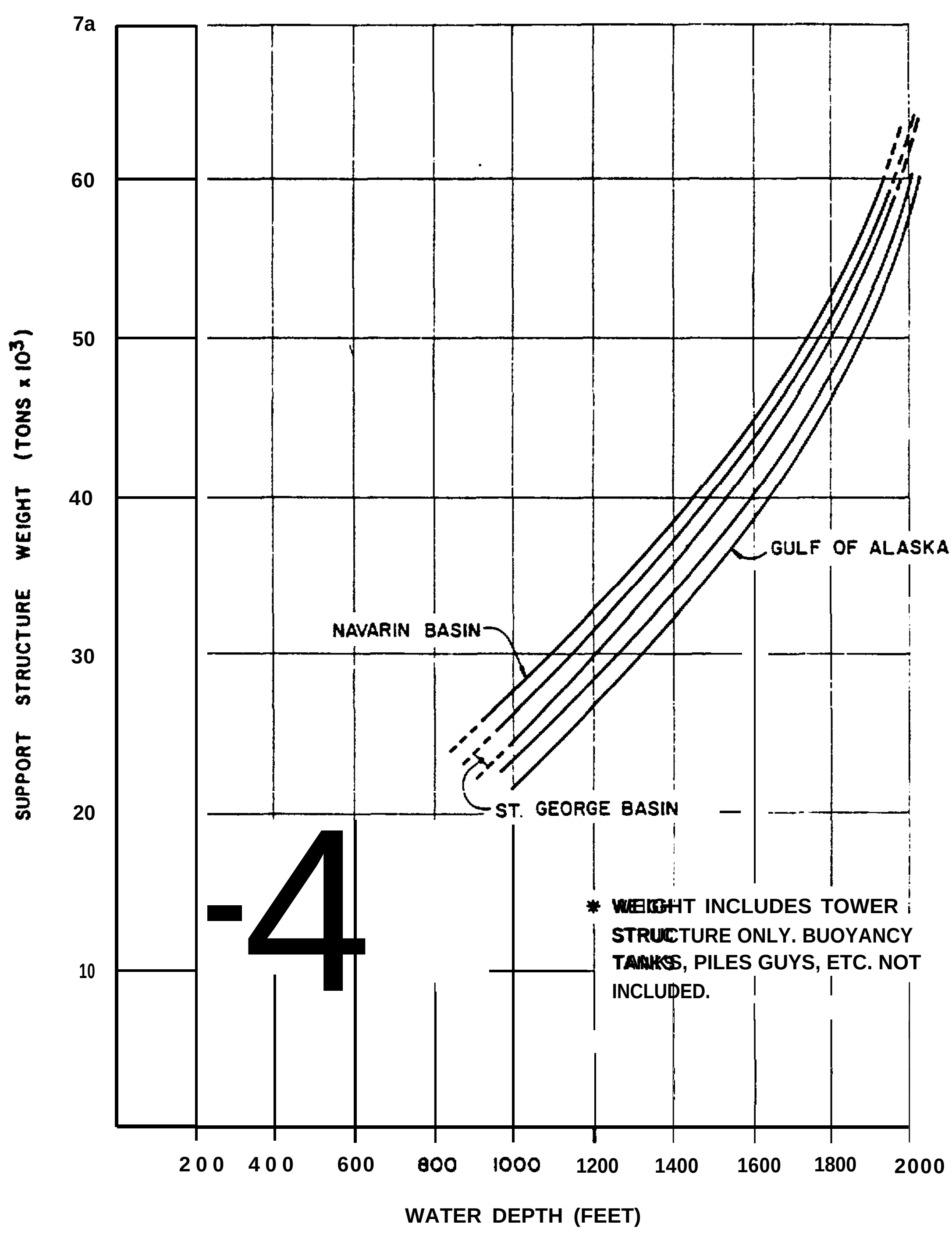
Figure 7-16 illustrates the results of structural tonnage versus water depth for varying tower dimensions to accommodate various topside area requirements. It can be seen that as the water depth increases, the effect on total structural tonnage becomes less significant with increasing topside load. For a compliant box section typical of the guyed tower, the tower dimensions and weight are influenced more by the need to provide adequate bending stiffness. This stiffness will influence the structural natural period of bending. An API minimum design requirement for the aspect ratio of length over cross-section diameter has been set at 10.

A more significant impact on total structural weight is the ice loads encountered in the Bering Sea. The guyline mooring system is most affected since it has to take most of the lateral load imposed by the ice. With respect to the tower itself, there were two ice-related considerations. First, the conventional framing pattern

FIGURE 7-16

GUYED TOWER

WEIGHT* VS. WATER DEPTH



at the water line had to be replaced with Cook Inlet type large columns to protect the water piercing appurtenances, and second, bending loads imposed by the ice loads had to be accounted for. The influence of seismic loads in the Gulf of Alaska on structural weight was determined not to be a significant factor. However, the foundation design was increased to account for soft soil conditions.

Costs for guyed towers in the Gulf of Alaska are presented in Figure 7-17. The influence of water depth on total installed cost is more influential than production rate in a given region, as was the case for tower structural weight. Costs in the Bering Sea are similarly greater because of the imposed ice loads which resulted in increased mooring system costs and greater steel tonnages. As was the case with conventional structures, fabrication costs become more significant with water depth.

7.5.3 Tension Leg Platforms

A brief description of the major components that comprise a tension leg platform (TLP) was given in Section 7.2. These components are the hull and the deck, the tether system, the riser system the seafloor anchor template system, and the tension piles. The two items that contribute the most to the overall TLP costs are the fabrication of the hull and deck and the tether fabrication.

In water depths of less than 1,000 m (approximately 3000 ft), the fabrication of the hull and deck is the largest cost item. However, beyond 1,000m water depths, the tether fabrication costs escalate much more rapidly than do the costs for hull and deck fabrication. As a result, at some water depth beyond 1000 m, tether fabrication becomes the greatest cost item. The cost increases can be directly related to increases in weight. Figure 7-18 graphically depicts the expected trend for the weights of the hull and deck and the tether systems as the water depth increases. The reason for the escalating

FIGURE 7-17

GULF OF ALASKA

GUYED TOWER COSTS *

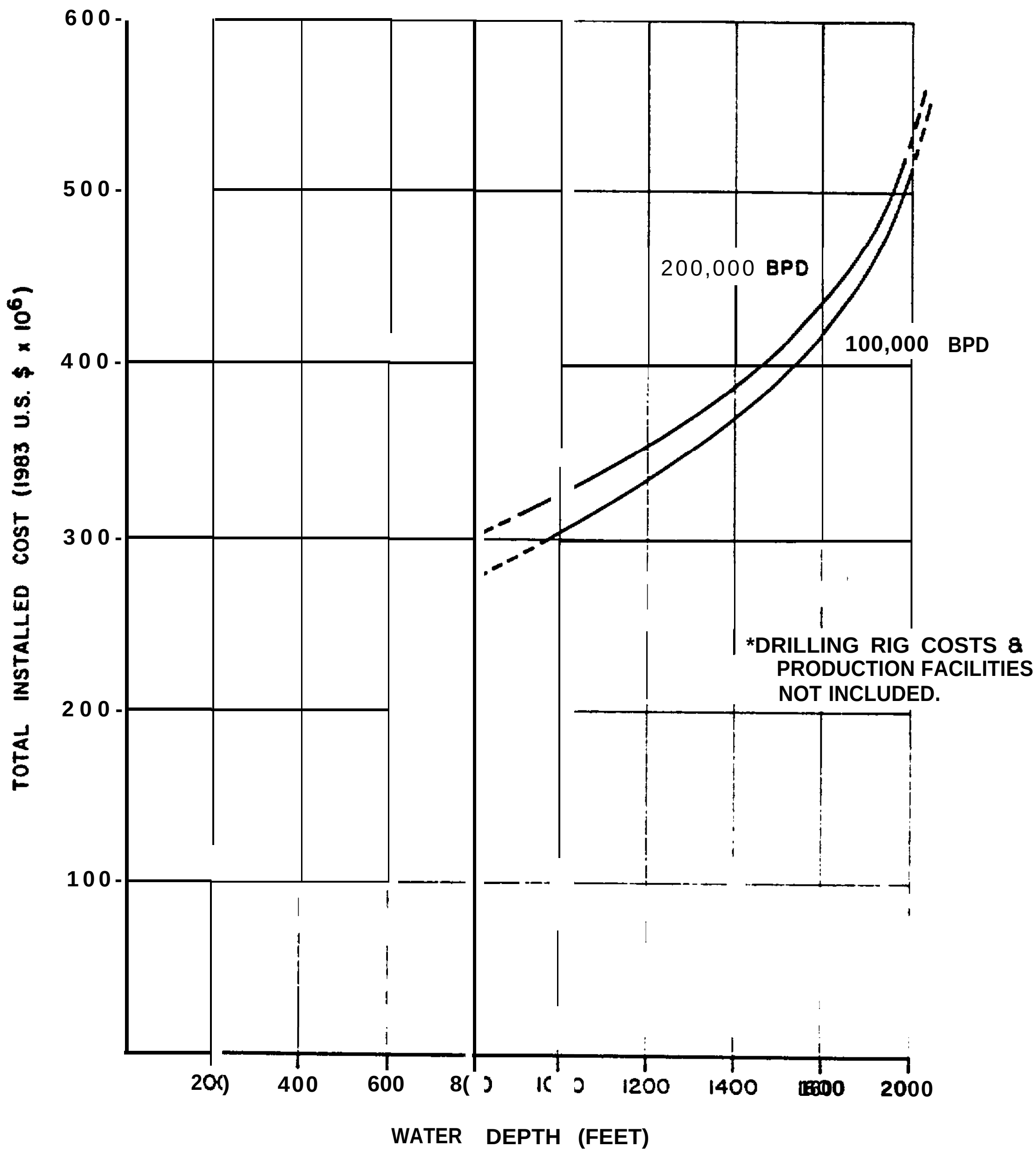
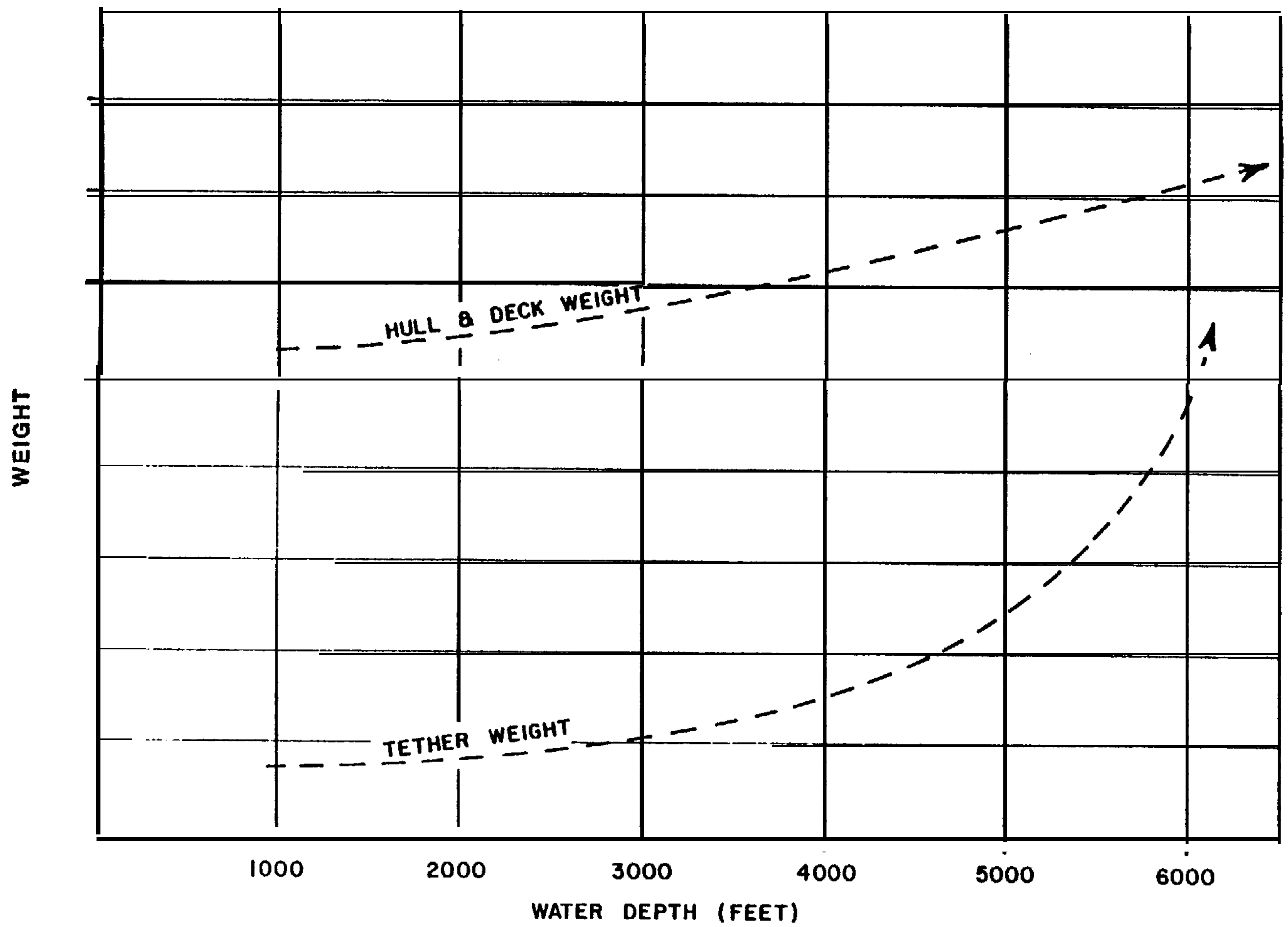


FIGURE 7-18

APPROX. WEIGHT FOR TLP TETHER SYSTEM

VS. TLP HULL & DECK SYSTEM



NOTE: BASED ON 8,000 TON PAYLOAD (EXCLUDING DECK STRUCTURE)
IN A SEVERE NORTH SEA TYPE ENVIRONMENT.

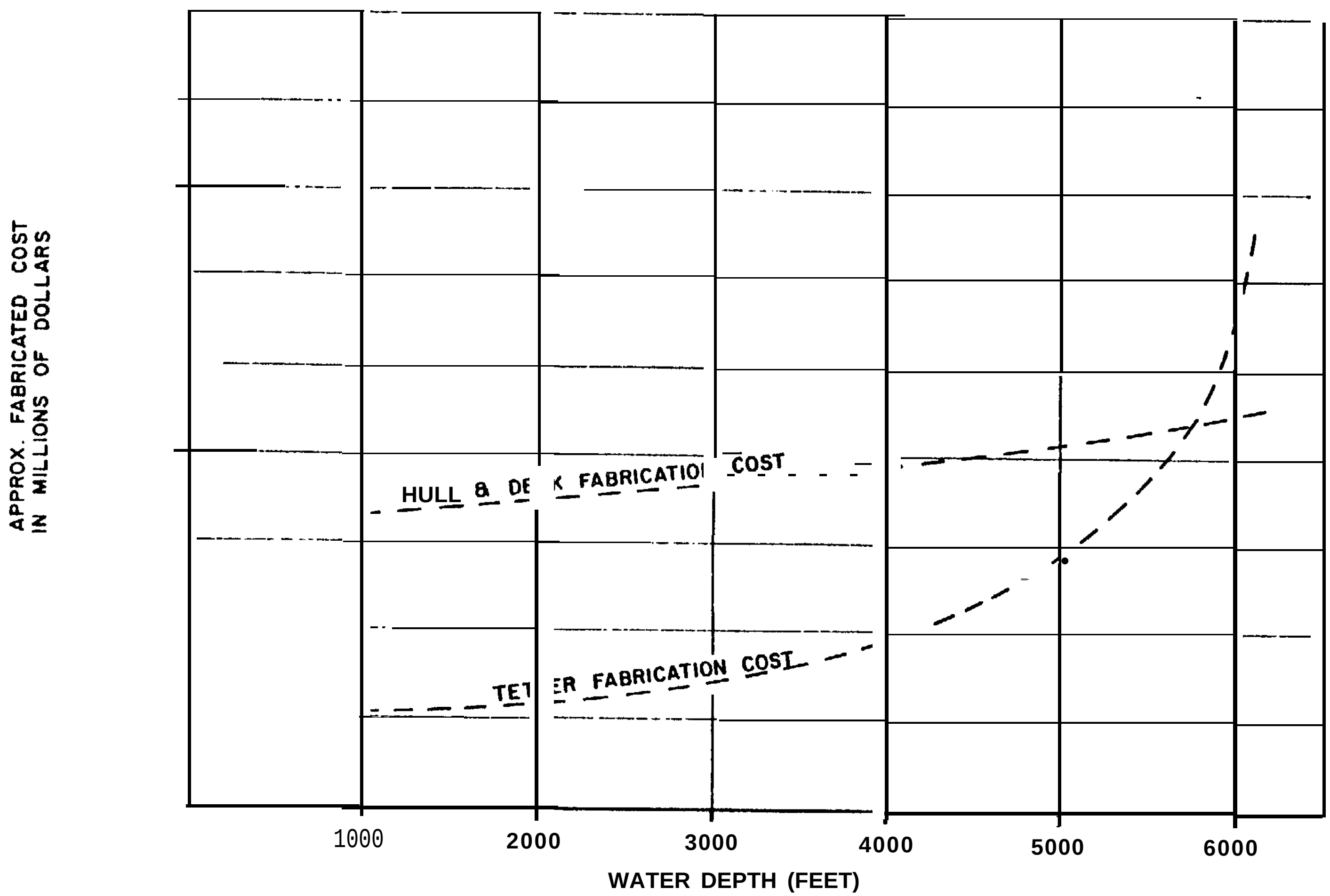
tether weight is that, as the water depth increases, the heave (as well as pitch and roll) periods of the TLP increase. This pushes the TLP's heave period closer to resonance with the periods typically associated with the predominant wave energy which, in turn, greatly accentuates the fatigue problem. Since the highly-tensioned tethers are very sensitive to 'fatigue, it is of the utmost importance to minimize the cyclic loading on the tethers. Therefore, as the water depth increases, the stiffness of the tethers must be increased to maintain the heave, pitch, and roll periods of the TLP under about 4.5 seconds. This is the approximate value beyond which resonant heave motions dramatically increase due to increased sea state energy. The increasing stiffness requirement leads to an increase in tether weight which is well beyond the effect derived from greater tether lengths alone.

The hull and deck weight are primarily affected by deck area and payload, the environmental loads of wind, wave, and current, and reactions to the tether forces. These influences will not change appreciably with water depth increases for a given region and a given set of production parameters. Therefore, the rate of increase of the hull and deck weight with water depth will not be nearly as great as that for tether weight in the deeper waters. Since weight can be related directly to cost, the tether cost will also escalate more rapidly than the hull and deck fabrication costs. In fact, Figure 7-19 indicates that between approximately 900 and 1,800 meters (3,000 and 6,000 ft) of water depth, the tether fabrication costs will begin to exponentially increase while the hull and deck fabrication costs increase at a very moderate, almost linear rate.

Another limiting factor related to the above discussion is that, as the payload increases, the mass of the hull and deck system also increases which, in turn, leads to an increase in the TLP's heave period. Since this is critical, as previously described, there is probably a limiting payload and therefore a limiting production rate

FIGURE 7-19

APPROX. FABRICATION COSTS FOR TLP TETHER SYSTEM VS. TLP HULL & DECK SYSTEM



NOTE: BASED ON 18,000 TON PAYLOAD (EXCLUDING DECK STRUCTURE) IN A SEVERE NORTH SEA TYPE OF ENVIRONMENT.

for which the TLP can economically be utilized. In this context, for very deep waters, it appears that the 100,000 BPOD level of production is feasible, but that the 200,000 BPOD level may not be. It is still too early in the development of the TLP concept to be more definitive about such limiting factors.

The hull fabrication can be divided into three elements: the columns, the pontoons, and the nodes at the column/pontoon intersections. The columns will be more expensive to fabricate per unit weight than the pontoons because the columns contain all the tendon attachment structure and equipment as well as several deck levels housing tensioning, motion compensating, and other pieces of installation and operational equipment. The nodes will be more expensive than either the columns or the pontoons on a unit cost basis because of the tremendous amount of complicated, high quality stiffened structure involved at the intersection of the column and pontoon elements. Studies have indicated that large hot spot stresses exist at the column/pontoon intersection which could cause fatigue problems (Ref. 44). Therefore, designers may choose to use steel castings for parts of the nodes to create smooth transition profiles and to move welds away from highly stressed locations. Casting is considerably more expensive than typical fabricated steel. In addition, the tolerance requirements for node fabrication will be greater than for the columns and pontoons in order to help minimize hot spot stresses.

Thus, the need for a higher quality of structure at the nodes combined with the highly stiffened nature of the nodes, will lead to higher unit fabrication costs for the nodal elements. Some preliminary vendor information received in-house for use in certain TLP studies indicates the following approximate relationship for unit fabrication costs of the three hull elements: 1.40 (nodes) to 1.25 (columns) to 1.00 (pontoons).

The unit fabrication costs of the tethers will be the most expensive of all the major components of the TLP. Due to the critical nature of the tethers, their high sensitivity to fatigue problems, and the uncertainty surrounding their structural response, there is a need for a consistently high quality material product along their entire length. For the North Sea Hutton Field TLP, special l y "forged", high strength, conically threaded tethers similar to oil field drill strings were utilized. This has resulted in extremely high costs for the tethers in this prototype structure. It is probable that such costs will be brought down as the structural response and durability of the tethers over the life of the platform become better understood. However, the trend of the tethers requiring higher unit fabrication costs than for any other major system component is likely to remain intact for the foreseeable future.

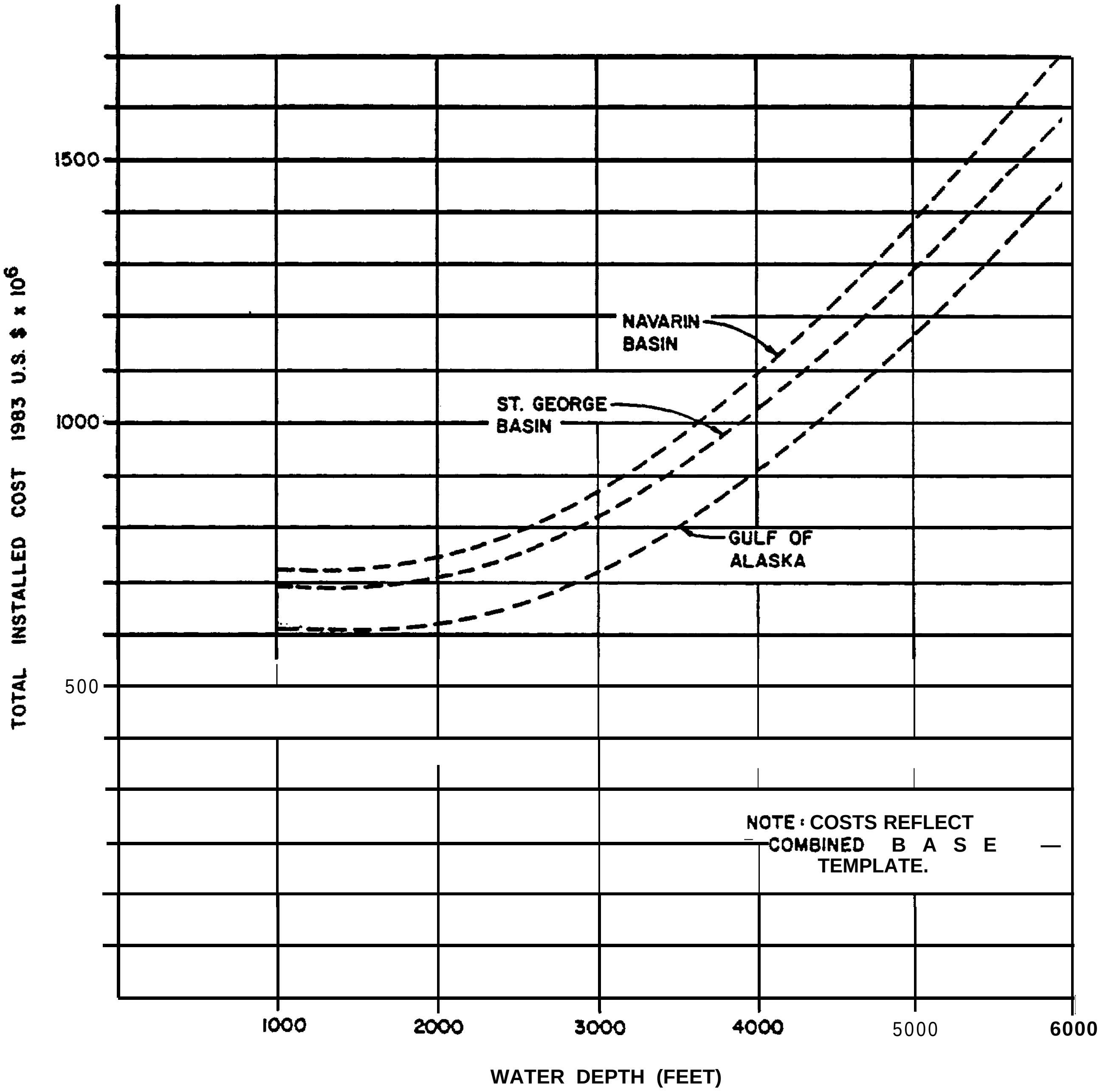
The estimated total installed cost of a TLP for approximately 100,000 BOPD production for each of the study areas is shown in Figure 7-20. These costs include the "combined base template option", since it is slightly more expensive than the multi-template alternative. For the design ice environments in the St. George and Navarin Basins, it was assumed that the TLP hull was locally strengthened and additional lateral support from a catenary mooring system, similar to that for a semi-submersible, was added to ensure the structural and operational integrity of the TLP during periods of ice invasions. These modifications are indicated in Figure 7-21.

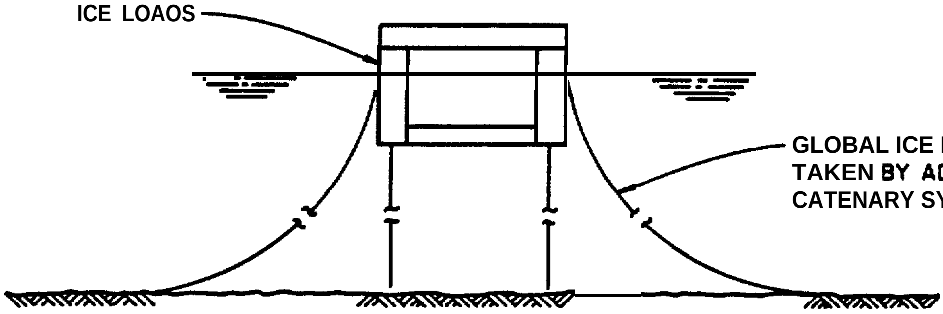
The catenary mooring system for such deep water applications is based on buoyant catenary lines to reduce the effects of cable weights and sag in the catenary. Such systems are currently in conceptual development. An alternative would be to add dynamic positioning capability to resist lateral ice loads. While cost data are presented over 1,800 meters (6,000 ft) in all regions, those figures for the Bering Sea regions and beyond 600 meters (2,000 ft) in the Gulf of Alaska should be considered academic because of a deficiency in credible experience for predicting costs.

FIGURE 7-20

TOTAL INSTALLED COST OF TLP

(100,000 b/d PRODUCTION CASE ONLY)





POSSIBLE TLP MODIFICATIONS FOR RELATIVELY LIGHT ICE ENVIRONMENTS OF DEEP WATER PORTIONS OF ST. GEORGE AND NAVARIN BASINS

FIGURE 7-21

7.5.4 Purpose Built Semi-submersibles

The basic design requirement for floating installations is to balance the vessel weight and buoyancy yet still maintain adequate stability. Therefore it is easy to understand the importance of keeping topside weight to a minimum and the center of gravity as low as possible. In achieving the final design, some compromise may be required on the facilities and procuring equipment in order to obtain a well balanced FPS.

The addition of topside equipment and deck space will automatically increase the topside weight and raise the center of gravity. The designers must then increase buoyancy to compensate, and possibly relocate or revise the columns to maintain stability. The resulting vessel will be larger and consequently subjected to increased wind, wave and current loads and in turn an increase in the size of the mooring system, resulting in a further increase in topside weight.

Bearing this in mind, topside facilities weights and space requirements are crucial to design and must be established to a reasonable level of confidence once an operating scenario has been defined. Figure 7-22 defines typical topside facilities weight and area requirements for both semi-submersible and monohull systems. Primary drilling equipment is not included for either case. However, riser handling and workover units are included for the semi-submersible case. Mooring system weights and areas are not included.

The basic design parameters were prepared from data available in-house and from outside sources.

For the purpose of this study, preliminary dimensions for three parametric semi-submersibles varying in production levels from 100,000 BOPD to 200,000 BOPD each with ten day storage capacity but with no drilling capability were prepared.

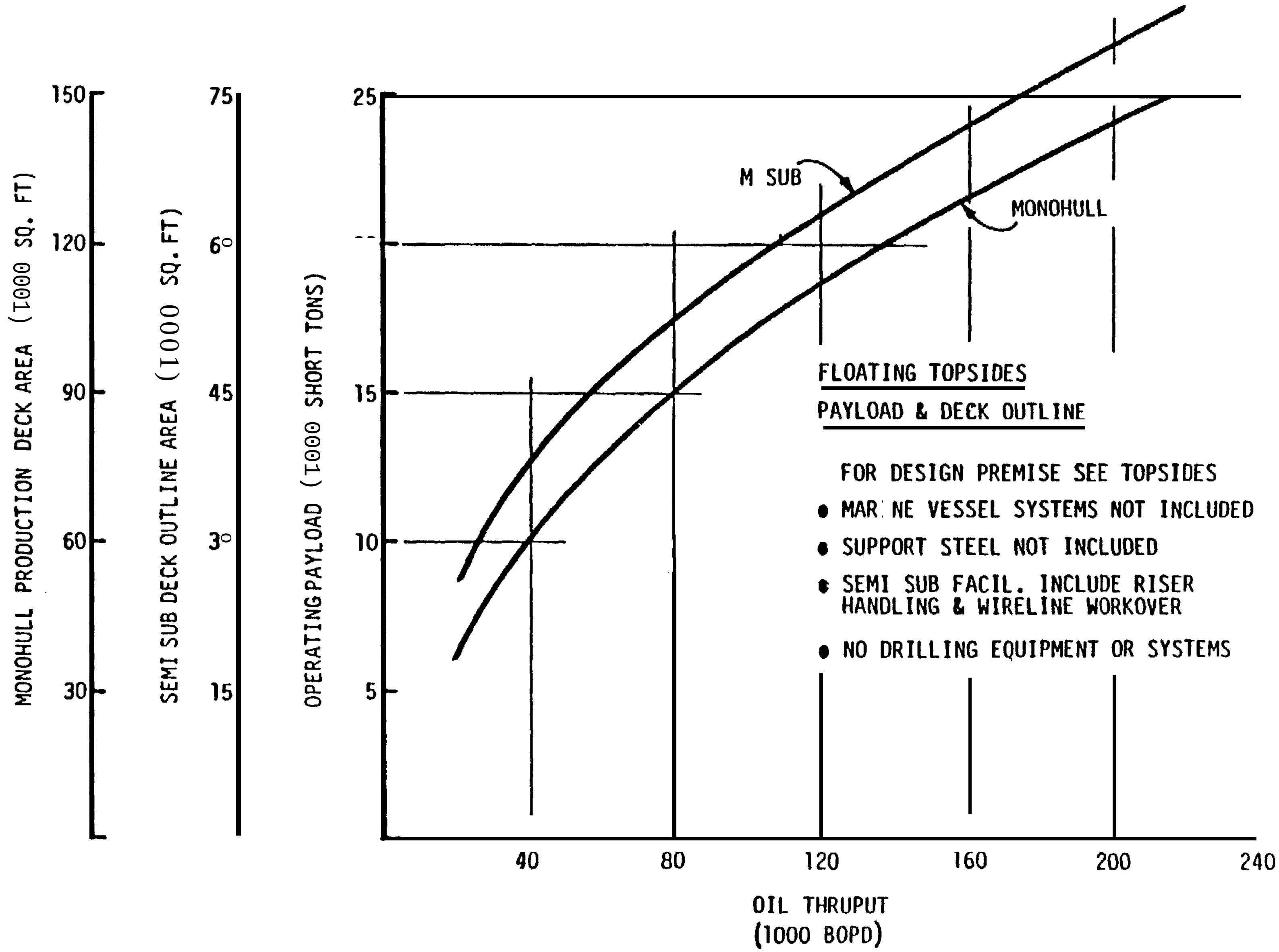

MONOHULL PRODUCTION DECK AREA (1000 SQ. FT)
150
120
90
60
30
SEMI SUB DECK OUTLINE AREA (1000 SQ. FT)
75
60
45
30
15
OPERATING PAYLOAD (1000 SHORT TONS)
25
15
10
5
M SUB
MONOHULL
FLOATING TOPSIDES
PAYLOAD & DECK OUTLINE
FOR DESIGN PREMISE SEE TOPSIDES
• MAR NE VESSEL SYSTEMS NOT INCLUDED
• SUPPORT STEEL NOT INCLUDED
• SEMI SUB FACIL. INCLUDE RISER HANDLING & WIRELINE WORKOVER
• NO DRILLING EQUIPMENT OR SYSTEMS
40
80
120
160
200
240
OIL THRUPUT
(1000 BOPD)

FIGURE 7-22

These designs have been based on the assumption that oil export will be by shuttle tanker and SPM system since a long distance trunk pipeline may be very expensive in extreme water depths. In orderto minimize production shut downs while waiting for tankers to connect to the SPM, the large lower pontoons have been sized to provide storage capacity for ten days of production, utilizing a ballast water displacement technique for the storage. This is acceptable provided that adequate ballast cleaning is incorporated in the topside facilities for use prior to overboard discharge of ballast. Should a pipeline to shore be used, this storage capacity would not be required and therefore the lower pontoons could be considerably smaller in size.

The design cycle is initiated at the deck. The required deck areas and payloads were determined using the curves in Figure 7-22. The columns were sized to provide adequate stability to the system in all loading conditions. Preliminary stability requirements have been based on providing a metacentric height of at least 3 meters (10 ft). The design of the two larger vessels incorporate eight columns. This has the effect of reducing the required size of the corner columns while reducing the deck span and hence the weight of the deck structure. The overall effect is to reduce the center of gravity.

The pontoon is provided with a central opening large enough to allow the riser or drill string to pass through even under extreme vessel motion. Within the pontoons space has been allocated for pipe trunks and access passages. Steel weight estimates have been based on cubic and area weight ratios derived from conventional semi-submersible drilling units.

For the sea ice conditions in the Bering Sea, the semi-submersible columns are strengthened and the mooring system protected. An extra open column would be added to protect the riser between the deck and hul 1.

Costs for the semi-submersible structure are presented in Figures 7-23a, 7-23b and 7-23c. A conventionally moored vessel has been assumed in all cases even though dynamic positioning may ultimately be proven viable; this alternative was not explored in the scope of this study. While cost data are presented to water depths of over 1,800 meters (approximately 6,000 ft), the data base for extrapolation should be considered academic beyond 600 meters (approximately 2,000 ft) because of a deficiency in credible experience to confidently predict costs in these water depths.

7.5.5 Purpose Built Monohull Systems

Hull Configuration

The outline designs for purpose built monohull vessels have followed the more traditional shipbuilding approach as applied to oil barge/tankers over recent years. The principle particulars for these vessels have been determined based on production capabilities of 100,000, to 200,000 BOPD with ten day storage capacity.

Design parameters were assumed before entering the design cycle. The vessel will have segregated tanks to ballast the vessel to a deeper draft with the oil tanks empty, thus improving the motion characteristics of the vessel while eliminating the need for additional separators. The length/depth ratio of the hull was chosen as approximately 14:1 stemming from the consideration of longitudinal hull strength. The hull beam/depth ratio was set as 3:1. This results in greater stability and reduction of the roll angle to which the process equipment is subjected. The area and weights required for the process equipment were obtained from the Figure 7-22. The resulting costs for monohull vessels are shown in Figures 7-24a, 7-24b and 7-24c. The cost equation was calculated on a volumetric basis and adjusted to conform with the weights of existing tankers of comparable size.

FIGURE 7-23a

SEMI-SUB COSTS

PURPOSE BUILT IO-DAY STORAGE

GULF OF ALASKA

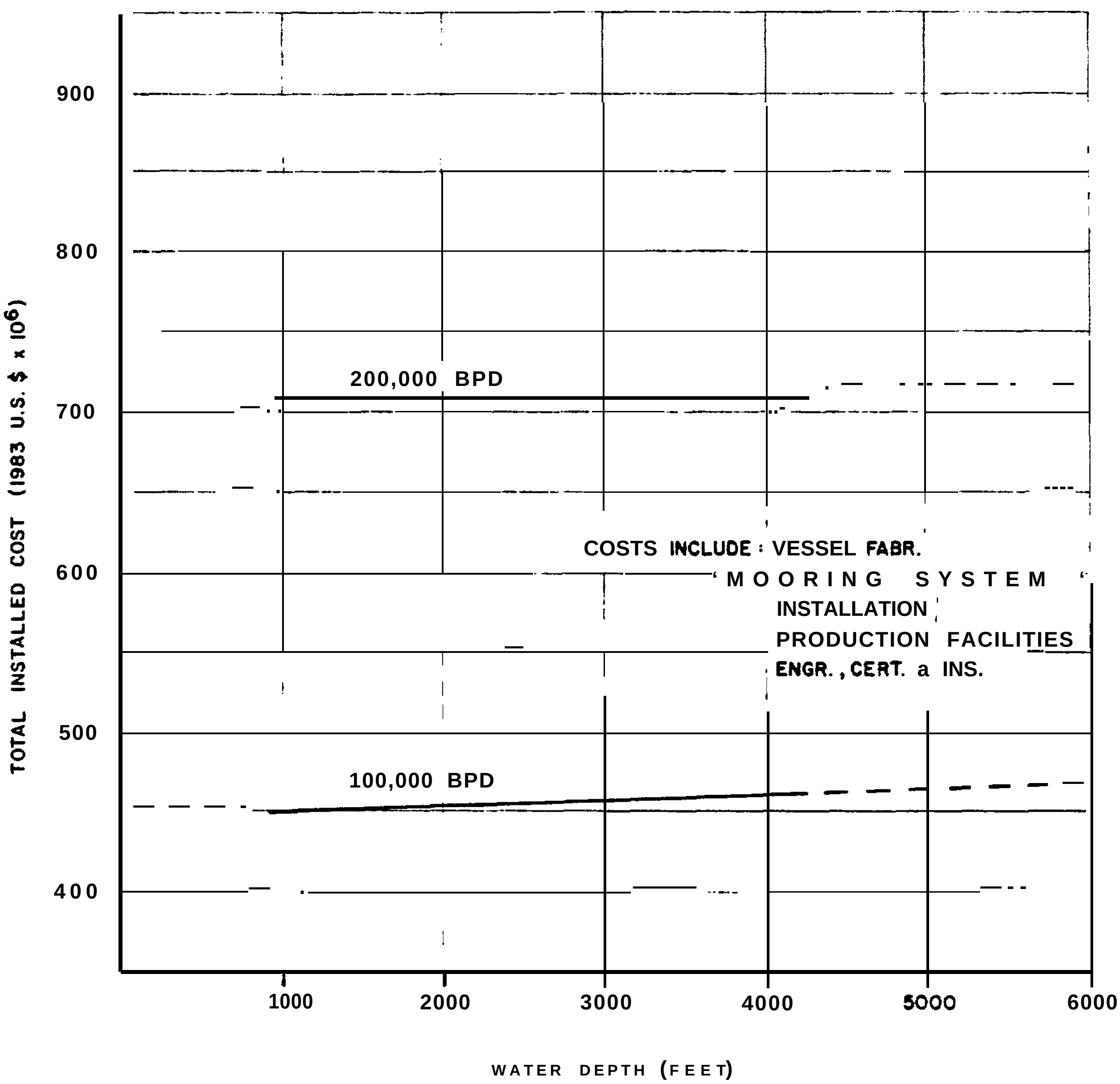


FIGURE 7- 23b

SEMI-SUB COSTS

PURPOSE BUILT 1O-DAY STORAGE

ST. GEORGE BASIN

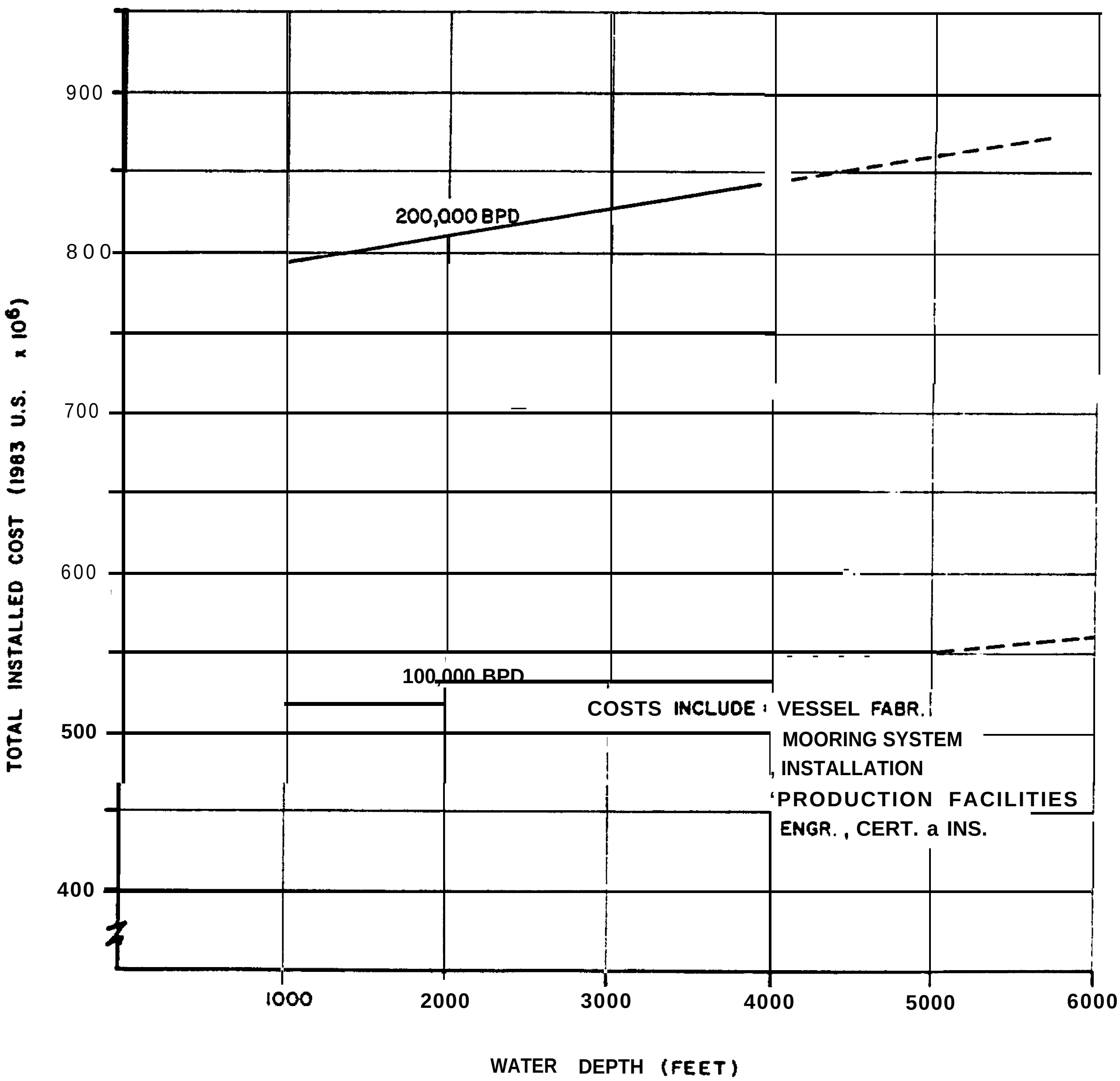


FIGURE 7- 23c

SEMI-SUB COSTS

PURPOSE BUILT 10- DAY STORAGE

NAVARIN BASIN

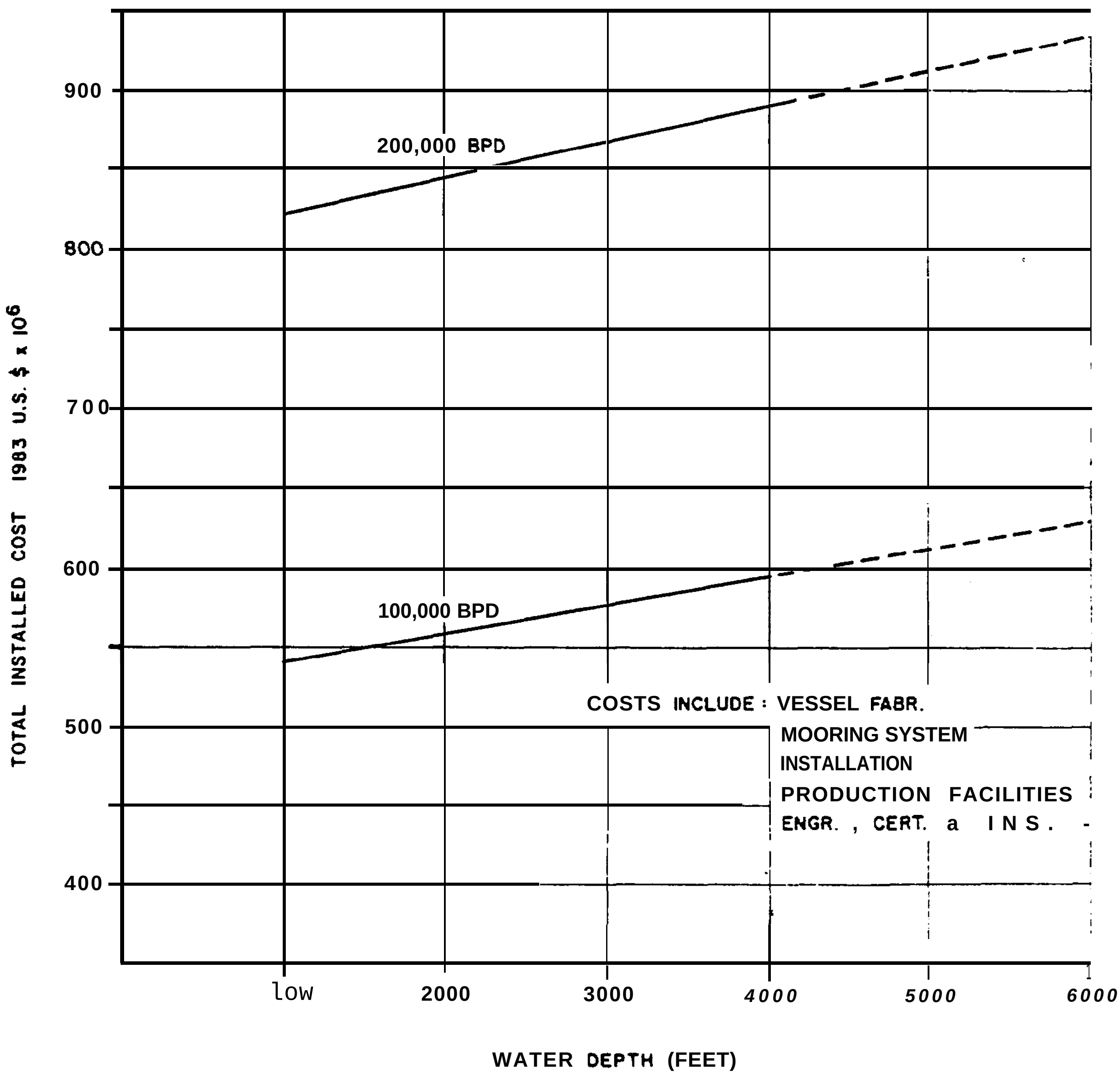


FIGURE 7-24a

MONO HULL COSTS

GULF OF ALASKA

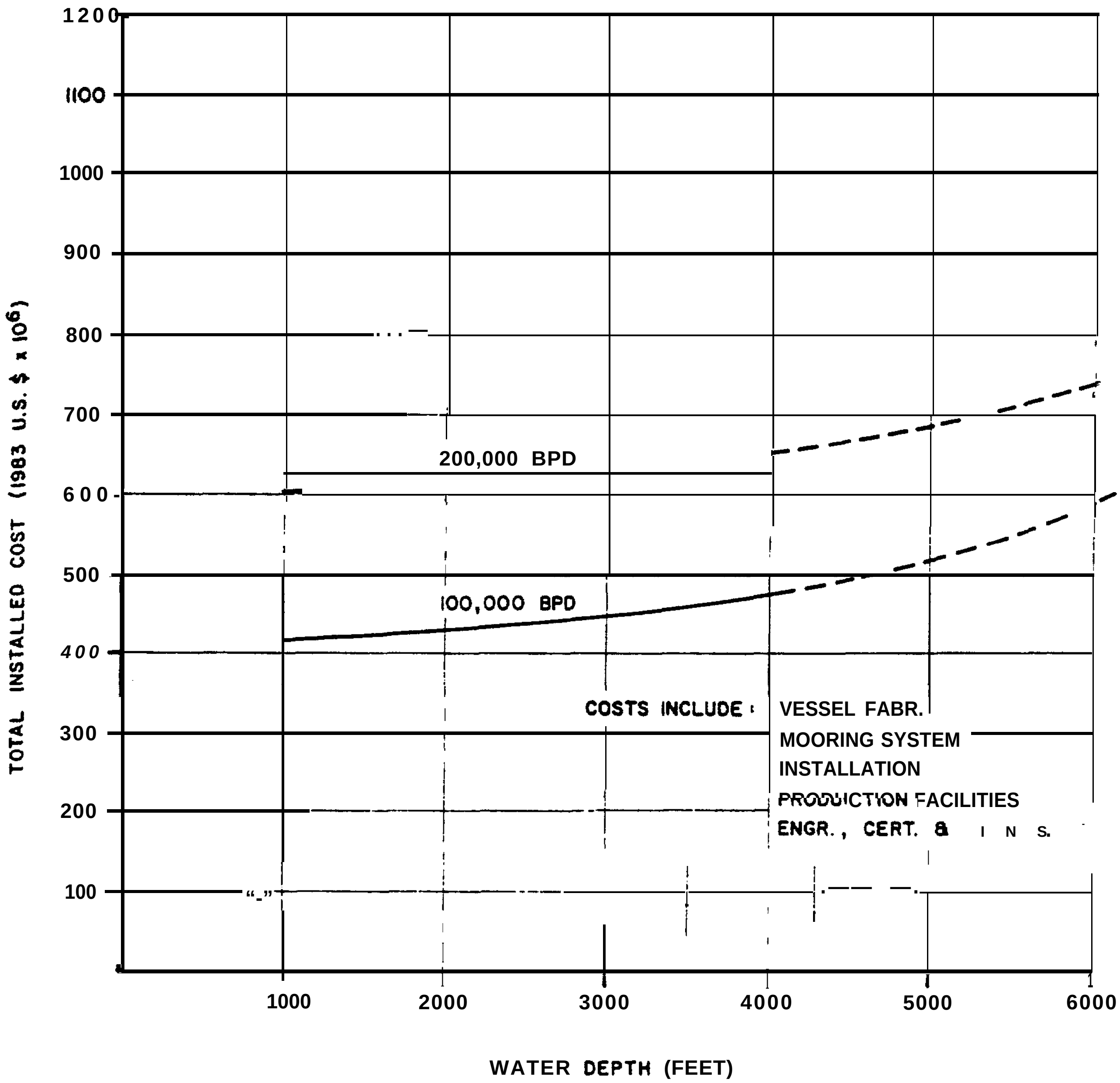


FIGURE 7-24b

MONO HULL COSTS

ST. GEORGE BASIN

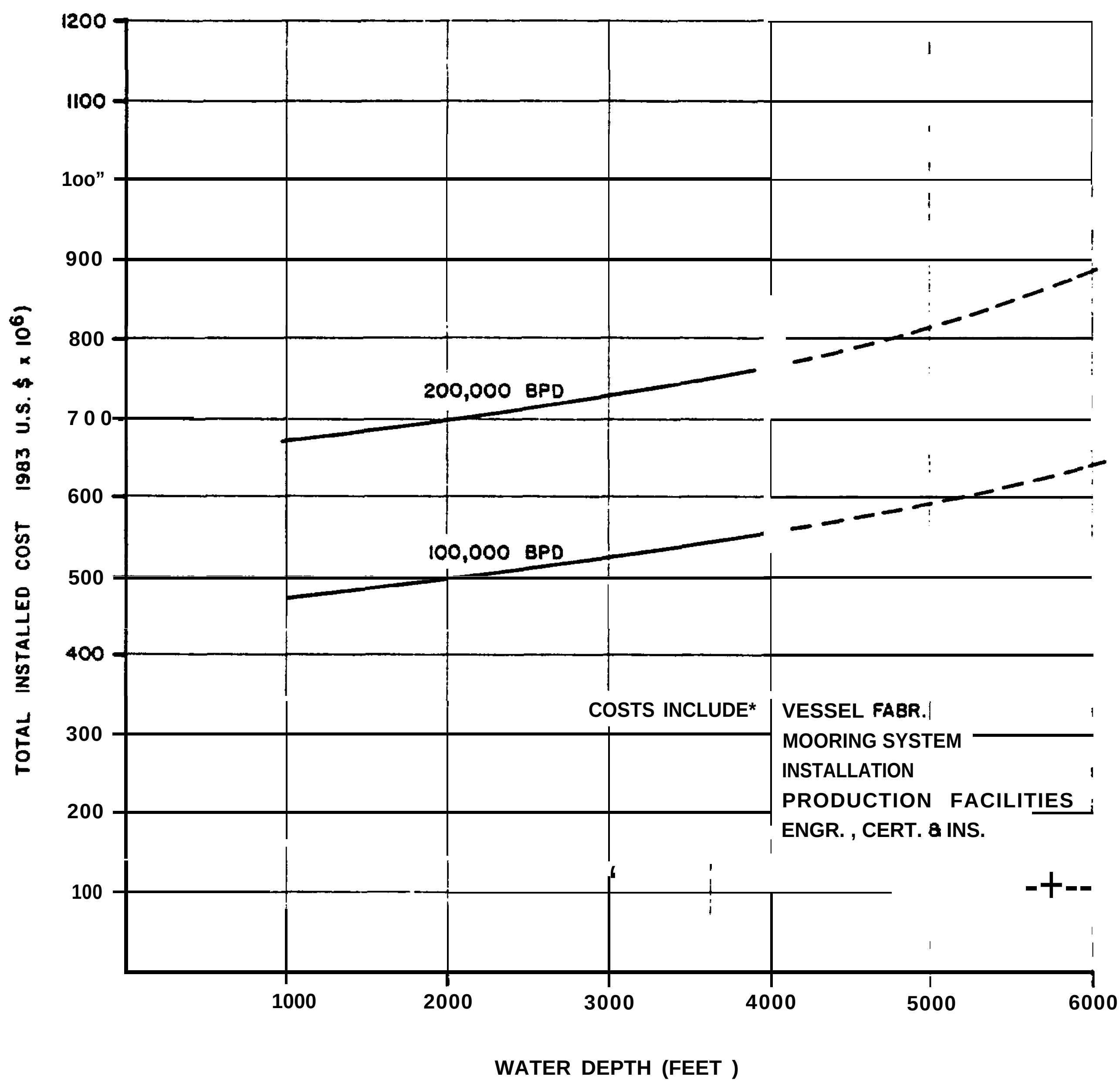
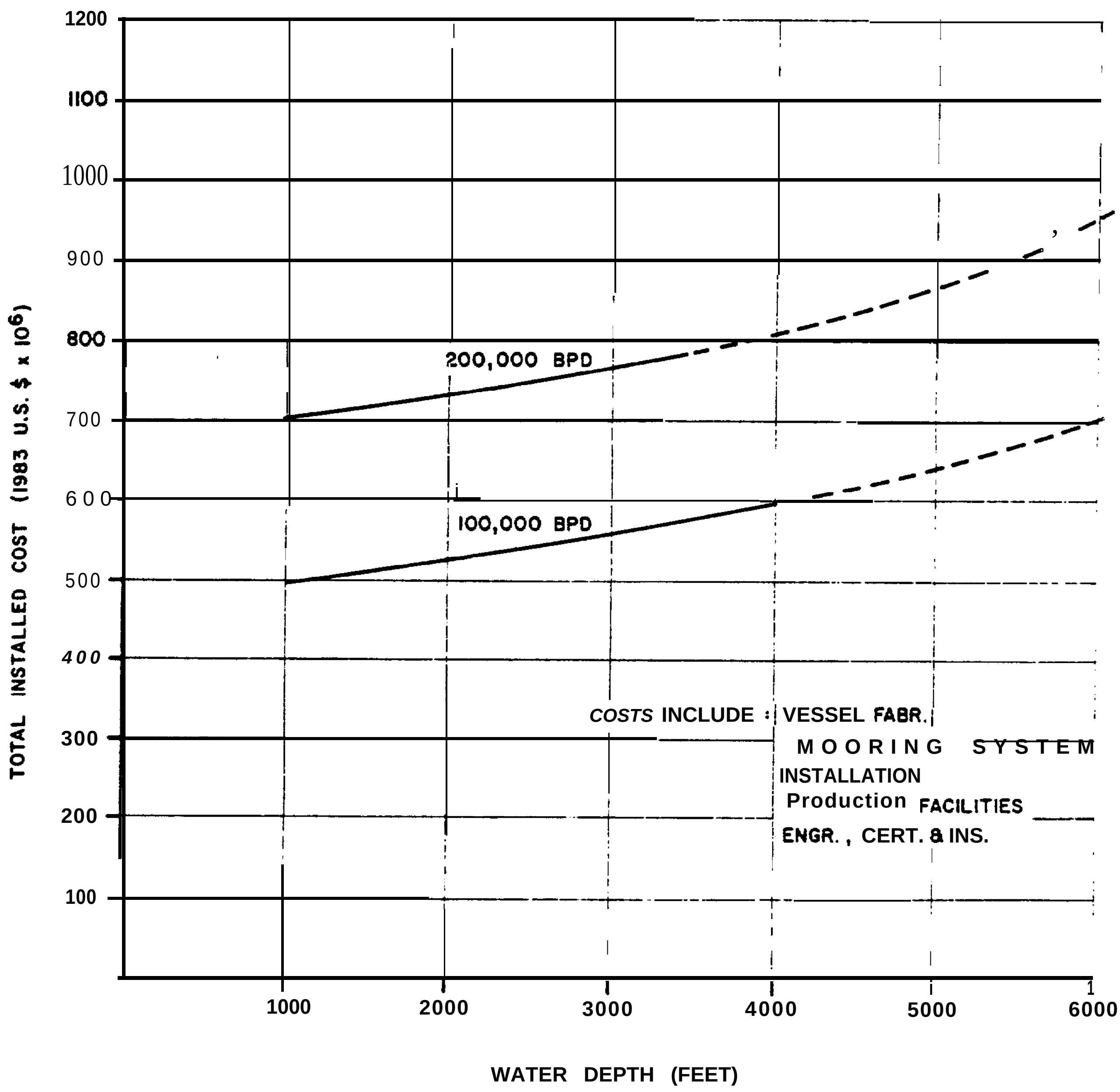


FIGURE 7-24 C

MONO HULL COSTS

NAVARIN BASIN



Single Point Mooring Systems

Monohull systems have usually taken the form of barges or converted tankers. In mild environments a multipoint catenary mooring system can be used. However, in view of the harsh environment in the study area a "weather vaning" single point mooring is preferable, as it minimizes vessel motions and environmental loads.

Three types of single point mooring systems appear to be suitable for permanent mooring of a floating production monohull vessel in the very deep waters considered in this study. The feasible types are the Single Anchor Leg Mooring (SALM), the Single Anchor Leg Storage (SALS), and the Turret mooring system. These mooring systems are discussed in Section 7.5.6

Recent discussions with an S.P.M. designer indicated that the anticipated technology water depth limit for SALM & SALS concepts are considered to be around 915 meters (3,000 ft). In water depths greater than this, a turret system could be used or a fully dynamically positioned vessel considered. A moored system has been assumed for this study.

Construction

As the design of these vessels would closely resemble oil tankers, it is logical that a shipyard with the appropriate experience would be well suited for such a contract. The process deck could be contracted separately and built as individual modular units. The se individual units could then be taken to the nearly completed vessel on deck cargo barges and lifted by crane on to the vessel. This system may be preferred as a means of reducing fabrication time or where the yard may not have the required experience in process plant construction.

As with the semi-submersible, several site preparations must be carried out before the vessel is towed to location. The main difference between the two systems is the mooring system which for the monohull vessel would probably be a single point mooring (SPM) attached to either the bow or stern of the vessel. The vessel would then be allowed to weather vane about the SPM, thus keeping the environmental loads on the moorings to a minimum.

7.5.6 Production Riser Systems

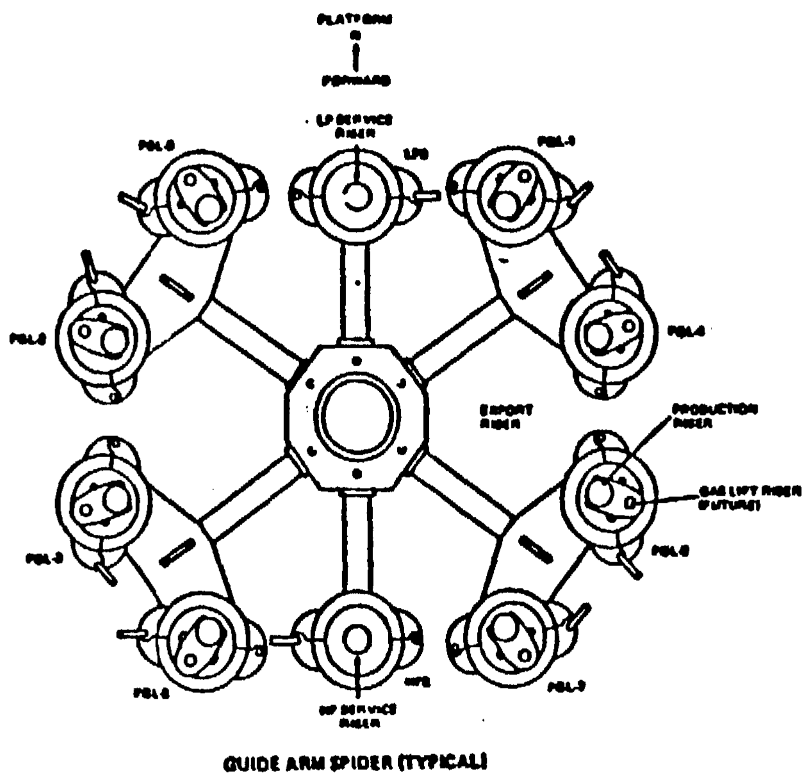
Production risers would be utilized as an integral part of an FPS and to supply production to a captive storage vessel located remote from the production platform. In this section two riser systems are discussed - one a rigid steel design and the other constructed of flexible hose. The advantages and disadvantages of each system are presented, followed by a technical discussion of each type of riser, listing the current technological limits of existing systems. Budget cost data for each riser system are also presented.

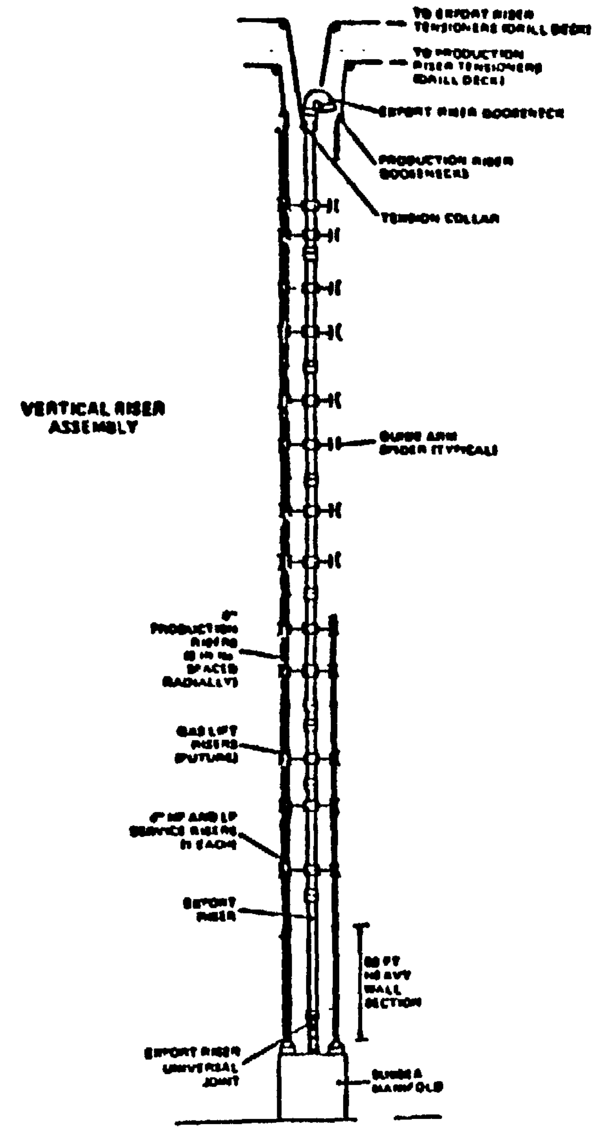
Rigid Riser System

There are two types of rigid riser system currently being proposed for production from a floating vessel.

The first is the non-integral type, shown in Figure 7-25, currently being used in the Buchan and Argyll fields in the North Sea. In general this consists of a central export riser surrounded by a number of smaller production lines with spacers at intervals down the riser. Each line is individually tensioned by a tensioner in the vessel moonpool area.

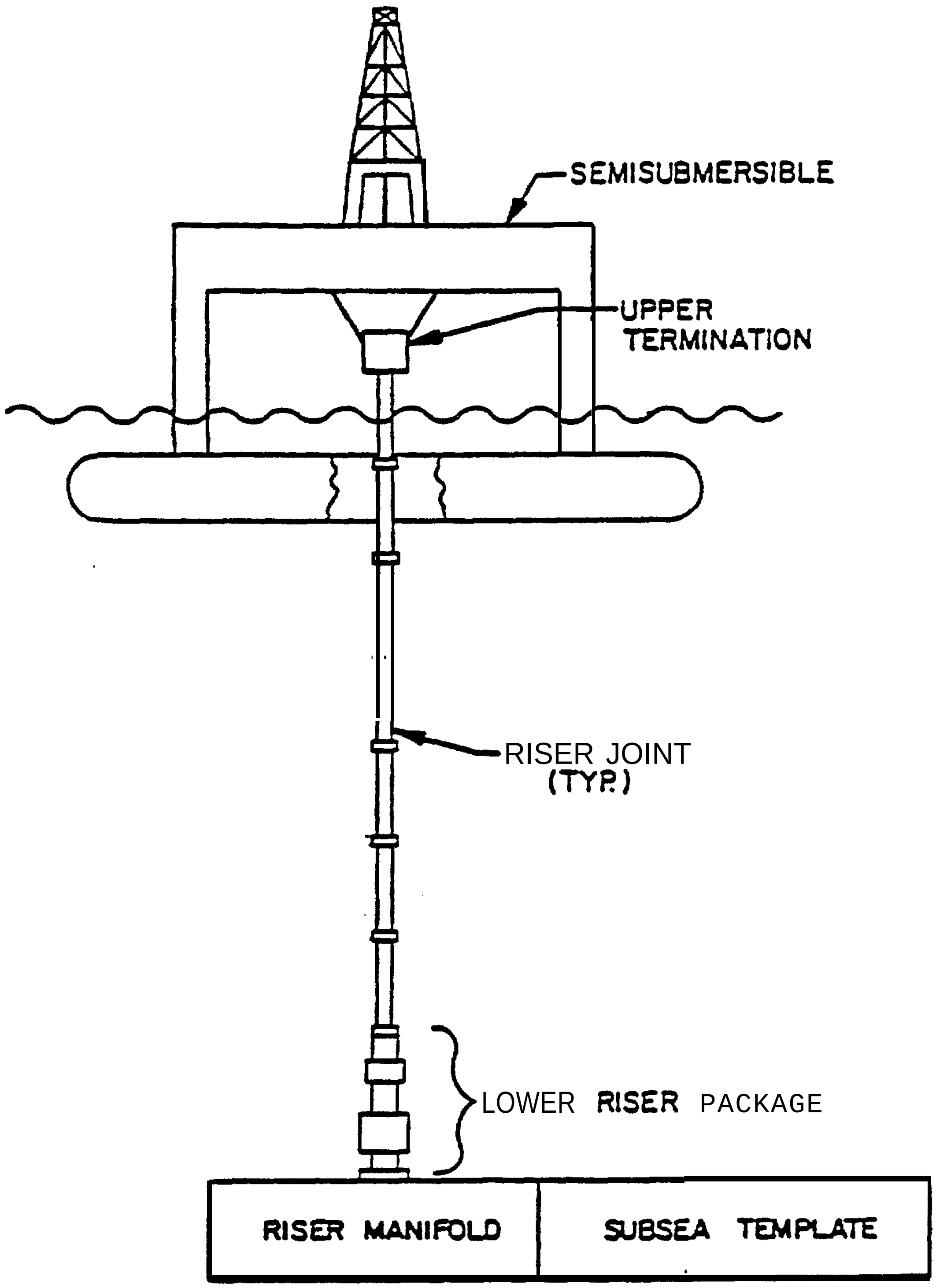
The second type of riser is the integral riser, shown in Figure 7-26, which consists of an outer cylinder which contains a number of smaller lines. Buoyancy is normally built into the riser to reduce the tension levels required on the vessel. The entire riser system is tensioned as one unit.





TYPICAL RIGID NON-INTEGRAL RISER

FIGURE 7-25



TYPICAL RIGID INTEGRAL RISER

FIGURE 7-26

The riser system is normally designed to remain connected to the subsea template over a certain range of environmental conditions and vessel motions. When these conditions are exceeded the riser is remotely released from the seabed, broken down into sections and stored on the surface vessel.

The primary advantage of the rigid riser is its proven performance in drilling and production in existing systems. Flexible risers have been designed for North Sea type environmental conditions but have not been proven in practice to date. In addition, for larger risers, the greater cost of the flexible pipe becomes significant.

The non-integral riser has a simpler construction than the integral type. The individual production riser and export lines are normally made of drill pipe which is readily available for this type of service and the production risers can be run and retrieved separately since all the risers are individually tensioned. However, while the system has some advantages in relatively shallow water, less than 150 meters (approximately 500 ft), it has the disadvantage of becoming overly complicated in greater water depths or if a large number of production risers are required.

Two existing floating production systems use the non-integral riser in the North Sea, one in the Buchan Field operated by British Petroleum and the other in the Argyll Field operated by Hamilton Brothers. Both systems use a semisubmersible vessel anchored above the template and an export line to a catenary moored loading buoy (CALM system) with a shuttle tanker to shore. Neither system has any significant amount of production storage and must shut down when the tanker leaves the loading buoy, either to go to shore to offload or because of weather. In general the Buchan system is a more sophisticated "second generation" version of the Argyll system and the designers, Sedco Hamilton, drew heavily on the experience gained in operating the Argyll riser when designing the Buchan riser.

Both the Buchan and Argyll risers consist of eight risers around a central export line, and this is generally considered to be the practical 1 imit of this type of system. With a greater number of lines the system becomes difficult to handle and the tensioner arrangement i n the moonpool becomes too complicated. In a similar manner the limiting water depth of such a riser system is 200 to 250 meters (approx. 700-800 ft) for North Sea conditions. Although the design is technically feasible, the riser becomes difficult to handle and the required tension levels excessive in greater water depths.

The production performance due to weather of existing systems in the North Sea has been in the range of 60-65%. However, the reason is usually that the tanker must leave the loading buoy. Normally the outer production risers are pulled first, and the central export riser is only pulled when the vessel heave reaches a higher limit. An estimate of the typical time to retrieve the riser is 12-24 hours in 150-meter (approx. 500 ft) water depth. However, if pulling the riser becomes a regular operation, this time can be reduced considerably once the crew becomes practiced at the maneuver, although greater water depths will significantly increase this time requirement.

Integral Riser

Integral risers have been used by drilling vessels for production tests in deep water. The primary advantage of the system is that it can be designed for deeper water since it only requires one tensioning system and the tension levels can be reduced by adding buoyancy to the riser. Against this, it is rather more expensive than the non-integral riser and it has to be fabricated as a single unit rather than using drill pipe which is readily available.

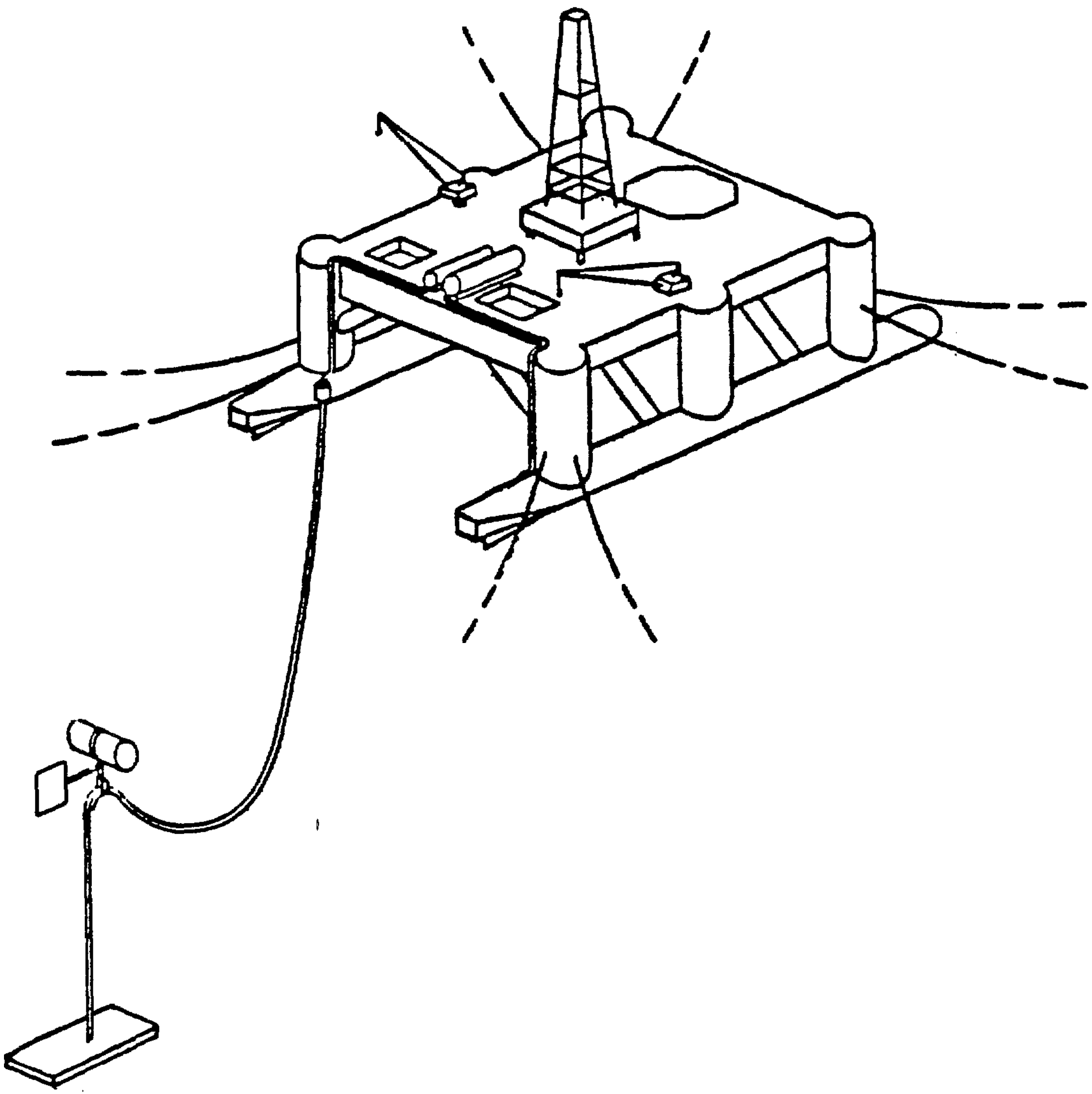
An advantage of the integral system is that it allows rapid disconnection from the riser base, whereas the non-integral system takes a much longer time to be broken down and disconnected. Like the non-integral riser, it has the advantage of proven performance in similar environmental conditions.

As mentioned previously, integral production risers have been used in deep water during drilling and testing operations. While the arrangement proposed *in* this study is fairly complex, it appears that the technology is available to design such a riser in water depths up to 1,830 meters (approx. 6,000 ft). For example, preliminary designs have been carried out for a riser containing up to 24 lines for use off the Atlantic coast in 2,300 meters (approx. 7,500 ft) water depth. One area which requires some development work is the seals for gas injection lines. These high pressures are at the limit of existing technology. However, this requirement is not addressed in the scope of this study.

Flexible Riser Svstem

The flexible riser systems that have been used in practice have all been used in relatively mild environments' conditions, most notably in Brazil. These risers are designed to stay in place during the worst weather conditions. An example arrangement of such a riser is given in Figure 7-27. This arrangement features a subsea buoy which is used to provide tension to the lower section and replaces any tensioners on the vessel.

The main advantage of a flexible riser system is that it remains connected in all weather conditions, thus allowing more efficient production from the field. However, the material cost is relatively high, especially in deep water, and a subsea buoy is required to provide tension to the lines.



TYPICAL FLEXIBLE HOSE RISER

FIGURE 7-27

The major disadvantage of the system is that it has no proven record in the environmental conditions or the majority of water depths given in this study. However, studies carried out by the manufacturer indicate that the system is feasible in water depths up to 760 meters (approx. 2,500 ft). One area of concern is the environmental conditions for the Bering Sea which may require hose connections below the water line for protection from sea ice.

Composite System

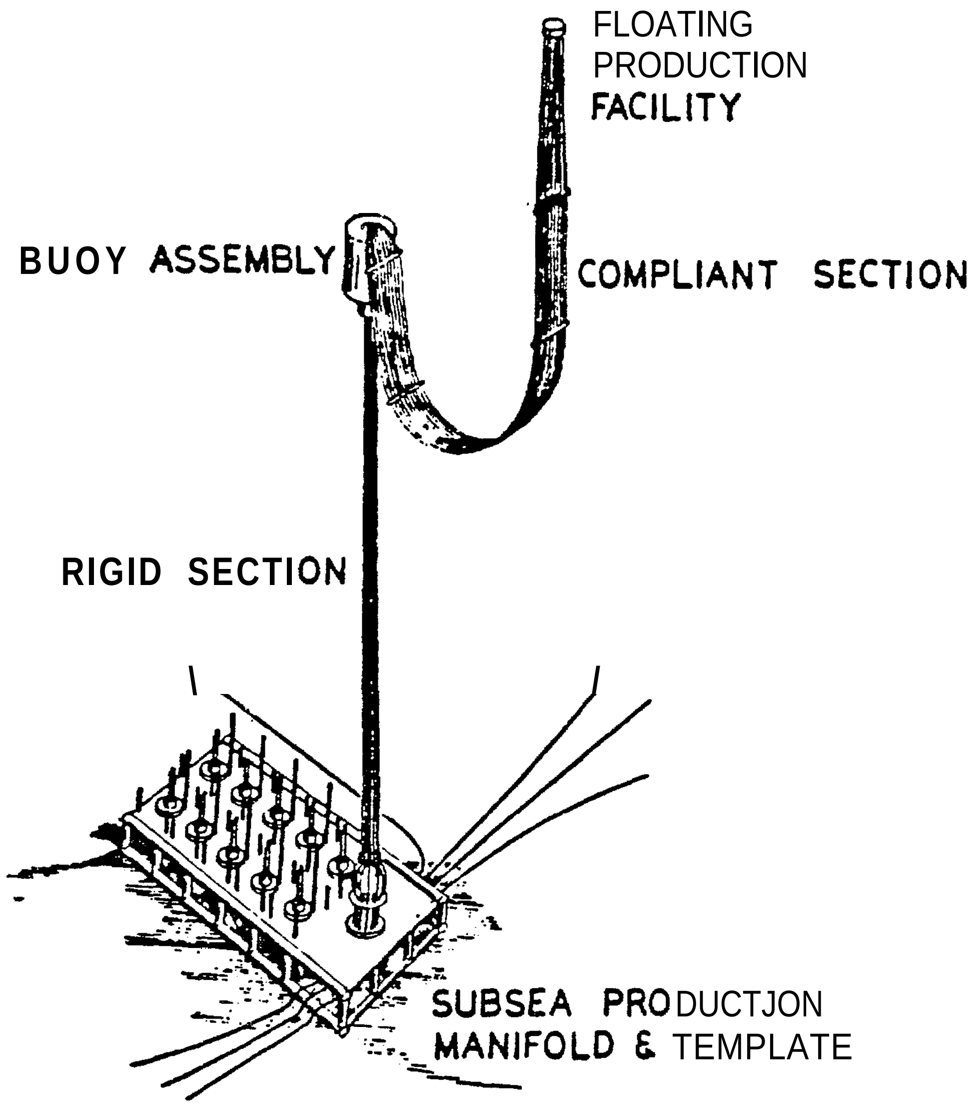
A compromise between rigid and flexible riser systems which may eliminate many of the disadvantages of both systems is shown in Figure 7-28. This system is composed of a rigid riser system from the sea floor to 60 meters (approx. 200 ft) below sea level. This section of riser is supported by a subsurface buoy. A flexible riser system then connects the buoy to the surface vessel. This riser system could be utilized with both semi-submersible and monohull vessels.

This system holds promise for the future, but has not as yet been utilized offshore. Detailed designs are, however, being performed at the moment. Cost Data for this system is not currently available, but costs in the range of the existing systems can be expected.

Subsea Template and Manifold

The subsea template structure serves as a collection point for the flow from all the subsea wells and as a base for the connection of the riser to the surface vessel. Existing systems generally consist of a tubular structure piled to the seabed by three or four piles, containing bases for a number of template wells and pull-in locations for pipelines from satellite wells.

Costs of both rigid and flexible risers for Floating Production Systems are depicted in Figure 7-29 as a function of water depth.



COMPOSITE RISER

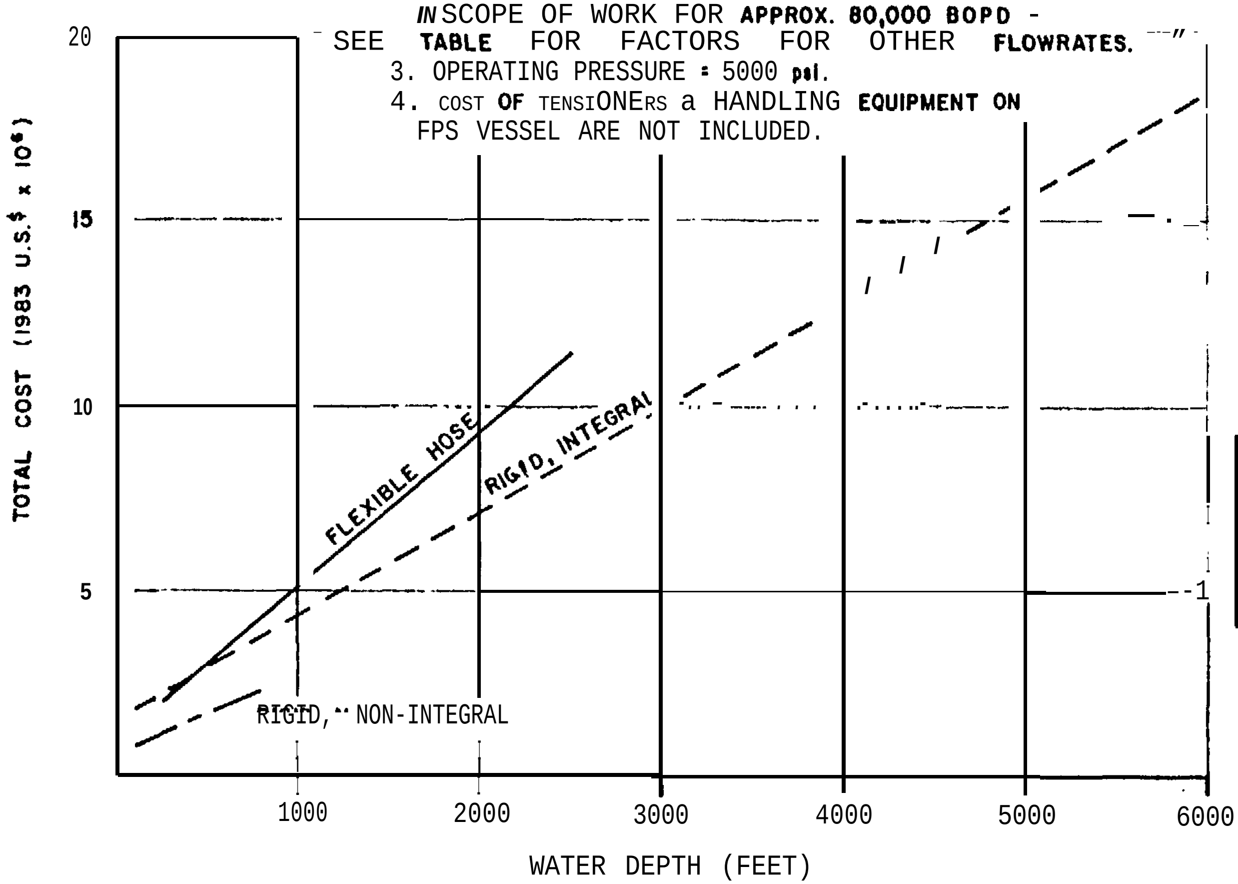
FIGURE 7-28

NOTES 1. COSTS INCLUDE HARDWARE & ASSEMBLY. INSTALLATION IS NOT INCLUDED AS IT WILL BE CARRIED OUT BY FPS VESSEL.

2. COSTS ARE FOR RISER CONFIGURATION AS SPECIFIED IN SCOPE OF WORK FOR APPROX. 80,000 BOPD - SEE TABLE FOR FACTORS FOR OTHER FLOWRATES.

3. OPERATING PRESSURE = 5000 psi.

4. COST OF TENSIONERS & HANDLING EQUIPMENT ON FPS VESSEL ARE NOT INCLUDED.



FLOWRATE	FACTOR
50,000	0.77
80,000	1.00
120,000	1.45
160,000	2.00

COST OF PRODUCTION RISER SYSTEM FOR FPS

FIGURE 7-29

8.0 ASSUMPTIONS FOR PRODUCTION FACILITIES COSTS

8.1 Introduction

Oil production facilities for deep water sub-arctic areas will be strongly influenced by experience gained in similar severe environments such as the northern North Sea, Cook Inlet and Prudhoe Bay. These facilities are normally self-contained on a single platform to provide drilling, production, testing, processing, reservoir pressure maintenance, oil pumping and housing of personnel. Numerous examples with production rates ranging from 50,000 BPOD to over 300,000 BPOD have been constructed in the British and Norwegian sectors of the North Sea. Each case of these facilities reflect the unique reservoir and environmental conditions plus the design state of the art prevelant at the time of field development.

Included in this section is the relevant experience and associated cost data base factors that will influence design and cost development for sub-arctic production facilities.

8.2 References

8.2.1 Review of Existing Systems

An extensive literature search was made to establish design parameters and characteristics of existing facilities that are comparable to those that will be required for sub-arctic areas offshore Alaska. The following periodicals provided varying amounts of information during this search:

Journal of Petroleum Technology
Petroleum Engineer International
Ocean Industry
Off shore
Offshore Engineer
Oil and Gas Journal

Also consulted were previous in-house studies and reports and the published proceedings of both the Offshore Technology Conference (OTC) and the European petroleum Conference (Europec).

The main problems encountered during the search were that information for various projects was reported in different manners with varying degrees of detail and accuracy, and that isolated cost information for topsides facilities only was scarce and difficult to extract. Deck areas were not listed in many cases, and topsides weight information was often not adequately defined as "dry" or "operating." Despite these problems, enough information was gathered for large drilling/production platforms to provide reliable weight and cost relationships for a wide range of production capacities. Table 8-1 contains the physical data obtained and used in the study. Topsides costs are not tabulated because of the large variations in time spans, currencies, and degrees of detail in which they were reported. The methodology used to develop the cost curve from the data available is discussed in Section 8.4.

British North Sea

Twenty-three (23) field developments in the British Sector of the Northern North Sea were studied to develop area, weight and cost relationships for platform topsides facilities assumed to be similar to those that will be required for the study areas. Water depths ranged from 150' in the Beatrice Field to 610' for Magnus Field. Individual platform design capacities ranged from 60,000 to 280,000 BOPD. Oil characteristics ranged from the 29° API, 110 GOR oil at

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/01 L RATIO (SCF.Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M_2)	TOPSIDES OPERATING WT. (TONNES)
U.K. North Sea								
Argyll/Hamilton (Semi-Sub)	76/250	70,000 BOPD	39″	220	None	8 Subsea Risers	N.A.	
Auk/Shell (Steel Jkt)	87/285	80,000 BOPD	37°	150	One	12	1,720	13,100
Beatrice "A"/Britiol (2 Steel Jkts)	4 6/1 50	100,000 BOPD	39°	100	One	32	N.A.	10,100 Total
Beatrice "B"/Britoil (Steel Jkt)	46/1 50	29,000 BOPD	39″	100	None (One W.0)	12	N.A.	N.A.
Beryl "A''/Mobil (Cone rete)	119/390	150,000 BOPD	36.5°	815	Two	40	N.A.	22,000
Beryl "B''/Mobil (Steel Jkt)	1 29/394	100,000 BOPD	36.5°	815	One	21+ 8 Subsea	2,538	22,150
S. Brae/Marathon (Steel Jkt)	11 2/367	100,000 BOPD	37°	650	Two	46	N.A.	33,000
N. Brae/Marathon (Steel Jkt)	99/326	75,000 BOPD 400 MMSCFD	45°	5,000	N.A.	15	3,240	37,000
Brent "A''/Shell (Steel Jkt)	140/460	100,000 BOPD	38°	1,750	One	28	2,200	17,400

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
M M E 01-I-SHORE FIELDS

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/OIL RATIO (SCF. Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M_2)	TOPSIDES OPERATING WT. (TONNES)
U.K. North Sea (Cent'd)								
Brent "B''/Shell (Concrete)	139/456	150,000 BOPD	38°	1,750	One	38	3,400	23,200
Brent "C''/Shell (Concrete)	140/462	150,000 BOPD	38°	1,750	One	40	4,000	30,000
Brent "D''/Shell (Concrete	142/466	150,000 BOPD	38°	1,750	One	48	3,400	22,400
Buchan/B.P. (Semi -Sub)	120/394	72,000 BOPD	33.5°	310	None	8 Subsea	N.A.	N.A.
Cl aymo re/Oxy (Steel Jkt)	111/364	260,000 BOPD	29°	110	Two	36	N.A.	20,000
S. Cormorant/Shell (Concrete)	150/492	60,000 BOPD 30 MMSCFD	36°	600	One	36	4,200	23,000
N. Cormorant/Shell (Steel Jkt)	160/525	180,000 BOPD 45 MMSCFD	36"	300	One	40	2,079	19,000
Dunlin/Shell (Concrete)	151/495	150,000 BOPD 40 MMSCFD	36"	250	One	48	4,600	24,400
Forties "A"/BP (Steel Jkt)	106/348	725,000 BOPD	37°	315	One	27	N.A.	19,000

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
MEDIUM TO LARGE OFFSHORE FIELDS

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/OIL RATIO (SCF. Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M_2)	TOPSIDES OPERATING WT. (TONNES)
U.K. North Sea (Cent'd)								
Forties "B"/BP (Steel Jkt)	123/403	125,000 BOPD	37°	315	One	26	N.A.	19,000
Forites "C"/BP (Steel Jkt)	127/41 6	125,000 BOPD	37"	315	One	27	N.A.	19,000
Forties "D"/BP (Steel Jkt)	121 /397	125,000 BOPD	37°	315	One	26	N.A.	19,000
Fulmar/Shell (Steel Jkt)	82/269	180,000 BOPD	40°	525	One	36+ 6 Template	N.A.	N.A.
Heather/Union (Steel Jkt)	1 43/470	75,000 BOPD	35°	650	N.A.	40	N.A.	22,000
Hutton/Conoco (T. L. P.)	148/485	110,000 BOPD	30.5°	125	One	32	N.A.	16,000
N.W. Hutton/Amoco (Steel Jkt)	143/470	100,000 BOPD 60 MMSCFD	37°	450	Two	40	N.A.	26,700
Magnus/BP (Steel Jkt)	186/610	140,000 BOPD	39°	800	One	20+ 7 Subsea	N.A.	32,500

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
MEDIUM TO LARGE OFFSHORE FIELDS

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/OIL RATIO (SCF. Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M^2)	TOPSIDES OPERATING WT. (TONNES)
U.K. North Sea (Cent'd)								
Maureen/Phillips (Steel Gravity Base)	93/305	72,000 BOPD	35°	290	One	24	5,995	26,500
Montrose/Amoco (Steel Jkt)	90/29 6	60,000 BOPD	40°	700	One	24	2,250	N.A.
Murchison/Conoco (Steel Jkt)	156/51 2	150,000 BOPD	38°	390	One	27	N.A.	24,700
Ninian Central/Chevron (Concrete)	133/436	276,000 BOPD	35.9°	324	Two	42	4,345	36,000
Ninian Southern/Chevron (Steel Jkt)	141 /462	160,000 BOPD	35.9°	324	Two	42	4,420	26,000
Ninian Northern/Chevron (Steel Jkt)	1 40/459	90,000 BOPD	35.9°	324	One	25	2,538	15,300
Pipe r/Oxy (Steel Jkt)	143/470	350,000 BOPD	37°	350	Two	36	N.A.	N.A.
Tartan/Texaco (Steel Jkt)	142/465	75,000 BOPD 14,000 B/D NGL 60 MMSCFD	38°	850	One	30+ 6 Subsea	N.A.	14,500
Thistle/Britoil (Steel Jkt)	162/530	200,000 BOPD	38°	280	Two	60	5,723	25,000

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
M M t F SHORE IELDS

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/OIL RATIO (SCF. Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M_2)	TOPSIDES OPERATING WT. (TONNES)
Norwegian North Sea								
Gullfaks "A"/Statoil (Cone rete)	1 35/443	245,000 BOPD	32°	500	One	42		49,000 (Est)
Gullfaks "B"/Statoil (Gone rete)	1 40/459	160,000 BOPD	32°	500	One	38		25,000 (Est)
Statfjord "A''/Mobil (Conc rete)	1 45/475	300,000 BOPD	39"	1,000	One	42	5,200	50,000
Statfjord "B''/Mobil (Concrete)	1 45/475	185,000 BOPD	39°	1,000	One	42	7,800	74,000
Statfjord "C''/Mobil (Conc rete)	146/480	210,000 BOPD	39°	1,000	One	42+ 9 Subsea	7,800	50,000
U.S. Gulf of Mexico								
Cerveza/Union (Steel Jkt)	285/935	25,000 BOPD 100 MMSCFD			Two	40	1,943	N.A.
Lena/Exxon (Steel Guyed Tower)	305/1 ,000	25,000 BOPD 5,000 B/D Cond. 50 MMSCFD			Two	58	2,262	N.A.

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
MEDIUM TO LARGE OFFSHORE FIELDS

PLATFORM/OPERATOR (TYPE)	WATER DEPTH (m/ft)	PRODUCTION CAPACITY	API GRAVITY	GAS/OIL RATIO (SCF.Bbl)	NO. OF DRILL RIGS	NO. OF SLOTS	PLAN AREA MAIN DECK (M_2)	TOPSIDES OPERATING WT. (TONNES)
<u>U.S. West Coast</u>								
Beta/Shell (2 STeel Jkts	81/265	2[illegible],000 BOPD	1[illegible]°-22°	150-200	Two	80	Drilling- 2600; Production- 2928	N.A.
Harvest/Texaco (Steel Jkt)	204/670	60,000 BOPD	19°	300		50	2,231	14,520
Hondo/Exxon (Steel Jkt/Tanker)	259/850	45,000 BOPD 26 MMSCFC						

TABLE 8-1
PLATFORM TOPSIDES CHARACTERISTICS
MEDIUM TO LARGE OFFSHORE FIELDS

Claymore to the 45° API, 5,000 GOR gas condensate stream at North Brae. Most of the platforms employed only one drilling rig, but the larger capacity units used two. This is primarily a result of higher well productivity rates than those expected in the Alaskan Sub-arctic. The number of drilling slots ranged from twelve to sixty. Two of the developments, Argyll and Buchan, employed converted semi-submersible drilling units as processing facilities. These floating production units had no drilling slots, but instead produced through risers originating from a template on the seafloor which is connected to subsea wells drilled by other vessels. Some of the more recent bottom-founded installations produce both from subsea wells and from wells drilled from the platform. Most, but not all, of the installations have substantial water injection capability, and some are injecting gas for conservation purposes. A fairly extensive gas gathering system now exists in the U.K. sector, however, and most of the fields with excess gas production are tied into it.

Considering the very wide range of variables that govern field development, it is impossible to select any single British North Sea field as a model for sub-antic facilities. But, enough experience has been gained to provide realistic estimates of topsides characteristics and costs for a hypothetical range of production scenarios. Each new field must, of course, be evaluated on the basis of its own unique characteristics. Technological advances since the first Northern North Sea fields were developed will tend to reduce weights, areas, and costs, but winterizing and allowance for the more hostile Alaskan environment will largely offset these gains.

Norwegian North Sea

Although the Ekofisk area was the first of the giant Northern North Sea discoveries to be developed, it was not included in this study because of the multiplicity of facilities and fields it encompasses. This study tended to emphasize multi-purpose, self-contained facilities which performed drilling, production, pressure maintenance, and accommodation functions on the same platform. Two very large field developments which meet this description *are* Statfjord and Gullfaks.

A great deal of information on these two projects has been published. Since these platforms have all recently been (or are currently being) developed, they provide examples of the present-day philosophy for exploitation of large harsh environment fields.

Weights, deck areas and costs for these facilities are high in comparison with similar U.K. platforms. The report by Johannes Moe et al. in 1980 (Ref. 36) investigated the causes of cost escalation for Norwegian O.C.S. projects, including Statfjord "B". There were many reasons cited for the overruns, some of which are equally applicable to U.K. projects; but much of the weight and cost excesses on Statfjord "B" are due to Norwegian regulations, industrial practices, and government policy.

U.S. Gulf of Mexico

U.S. Gulf of Mexico platform installations are designed for much smaller production capacities than are those in the Northern North Sea, and of course the climate is much less severe. Two fairly recent installations, of interest because of the water depths encountered, were reviewed; Union Oil Cerveza Platform is designed to handle 25,000 BOPD and 100 MMSCFD in 285-meters [935 ft) of water; and Exxon Lena Platform, the first commercial guyed tower installation, is also designed for 25,000 BOPD, plus 5,000 barrels per day of condensate and (50 MMSCFD, in 305-meters (1,000 ft) of water. Both have two drilling rigs because of the vastly smaller well productivities in the Gulf of Mexico, as compared to the North Sea. Cerveza is different in another respect in that it is not designed for simultaneous drilling and production operations. Production will begin in 1985, after the drilling program is complete.

Since the design parameters of Gulf of Mexico facilities differ greatly from those expected to be encountered for the sub-arctic O.C.S., Gulf of Mexico data was not factored into the cost for this study.

U.S. West Coast

The U.S. West Coast platforms, concentrated off Santa Barbara County, California, present a unique set of challenges due to various environmental and regulatory demands and to reservoir fluid properties which are less favorable than those in the North Sea. Low gravity oil with high sulfur content and sour associated gas is characteristic of recent discoveries in the Santa Maria Basin. The supporting structures and topsides must be designed for seismic and conventional environmental loads, but the latter are less severe than those encountered in the North Sea. Production capacities in general run much lower as well.

Three field developments were investigated, but their characteristics are so vastly different from those expected for the Alaskan Sub-arctic that they were not incorporated into the cost development. Shell's Beta complex uses two steel, bridge-connected platforms in 80 meters (265 ft) of water to process 26,000 BOPD. Exxon's Hondo installation, which uses a steel jacket and a converted tanker to process 45,000 BOPD and 26 MMSCFD, is located in 260 meters (850 ft) of water. Texaco's Harvest Platform is expected to handle about 60,000 BOPD of 19° API crude (GOR = 300) in 204 meters (670 ft) of water. The combined plan areas of the two Beta platforms in shallow water are about 2.5 times the plan area of the single Harvest platform in 670 feet of water. Total topsides weight for Beta is somewhat heavier than for Harvest.

Other Areas

Considerable industry and government research and development effort is currently being expended to produce viable designs for Canadian and U.S. Arctic and Sub-arctic drilling and production facilities.

The design of the topsides facilities is not as directly affected by ice loading *as is* the design of the supporting structures; but once the latter is selected, the choice may affect substantially the topsides configuration. The approach in this study was not to attempt to quantify all possible topsides designs, but to determine area, weight and cost relationships based upon the U.K. North Sea model. These relationships will provide preliminary estimates for topsides facilities for a given production rate that can be factored up or down to suit specific conditions. Even if the layout turns out to be entirely conventional, the estimates will still need to be adjusted for variations in fluid properties, well productivities, environmental conditions, distance from shore, and all the other factors that affect equipment size and selection.

Consideration of Arctic and Sub-arctic design parameters at this stage are useful to help anticipate some of the problems that might be encountered. Their effects have been factored into the area, weight and cost curves, but no significant historical data yet exists for offshore production facilities in these frontier areas.

8.2.2 Review of Relevant Studies

Offshore studies during the past several years have been directed toward finding practical solutions for field developments in ever-increasing water depths and hostile environments. Much of the unpublished data gathered for National Petroleum Council's "U.S. Arctic Oil and Gas", a report to the Secretary of Energy published in December, 1981, has been useful in formulating topsides weight, area and cost relationships for this study, as has the information incorporated into in-house studies. Of particular interest and applicability are two very comprehensive reports covering installations in the British and Norwegian sectors of the Northern North Sea. Details of these studies and reports are contained in the subsections which follow.

National Petroleum Council Arctic Study (1981)

The National Petroleum Council was established on June 18, 1946, to advise the United States Secretary of the Interior on matters pertaining to oil and natural gas as they effect the national interest and security. Its membership includes recognized authorities within the industry as well as the chief executives of most of the country's leading exploration, production and service companies. Upon establishment of the Department of Energy in 1977, the Council's functions were transferred from the Department of Interior to the new department.

The purpose of the NPC is solely to advise, inform and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Several major studies have been undertaken in recent years on this basis. A request was made by Energy Secretary Duncan on April 9, 1980, for a comprehensive study of U.S. Arctic oil and gas development. The NPC completed the study in 1981 and presented it to the Department of Energy on December 3, 1981 (Ref. 2).

North Sea Reports

An on-going reference service published by Edinburgh stockbrokers, Wood, MacKenzie and Co., provides historical, technical and financial information for all operational and prospective field developments in both UK and Norwegian waters (Ref. 34). The service, which is continuously updated, provides total estimated field development capital and operating costs for each project. The capital costs are broken down into the following categories by year:

- Platform Structure
- Platform Equipment
- Platform Installation
- Development Drilling
- Subsea Installations
- Loading Buoys
- Pipelines
- Terminals
- Miscellaneous

This breakdown unfortunately does not provide topsides engineering and project management costs, nor does it isolate topsides fabrication, offshore installation and hook-up costs, which for the North Sea have been very substantial. Nevertheless, the estimates are consistent from project to project and enable one to compare one project with another on the basis of total project cost or any of the above-listed components. This reference service is by far the best available for any oil and gas province in the world and luckily covers the area which most closely resembles the expected environment to be encountered in the Alaskan Sub-arctic.

The Norwegian study looks at North Sea installations primarily from a historical perspective to determine why development costs for earlier Norwegian projects exceeded so dramatically all initial estimates and budgets. Several British developments are also analyzed, but in less detail. Entitled "Cost Study-Norwegian Continental Shelf," the report (Ref. 36) was submitted on April 29, 1980, by a steering group chaired by Johannes Moe in response to a royal decree of March 16, 1979, which requested the committee to "evaluate the factors which would be of particular significance for estimating the cost of future development projects, and to give advice concerning measures that should be implemented to limit the cost development". The report is therefore widely referred to as "The Moe Report". It is very comprehensive and should be read by any company or government contemplating off shore developments that would approach the scale of those in the North Sea. Some of the cost escalation may be attributed to uniquely Norwegian constraints, but much of it would be applicable to any multi-billion dollar undertaking. The primary causes of Norwegian project cost escalation were grouped as follows:

- Under-estimates
- Unforeseen inflation
- New authority directions (regulations)
- Increased operator demands
- Insufficient project execution

8.3 Influencing Factors for Sub-arctic Production Facilities

Offshore production facilities in the sub-arctic would most likely be self-contained to simultaneously drill, produce, process and quarter personnel, as proposed by the NPC Report *in* 1981 (Ref. 2). The severe environment and remote offshore locations would dictate this configuration which is a trend that was developed and refined in the North Sea and Cook Inlet operational areas. This influence would be particularly true in the northern Bering Sea or Navarin Basin. While the influence of remoteness and severe environment may be somewhat less in the St. George Basin and Gulf of Alaska, the use of self-contained, multi-function drilling and production facilities is expected to be favored in all the study regions.

Enclosed areas on platforms promote a better working environment for personnel, but there arises a requirement that considerations for fire and safety methods comparable to the existing arctic and sub-arctic areas be empl eyed. New developments i n personnel safety are under development for the North Sea and off the East Coast of Canada to meet the harsh climate conditions.

The NPC in 1981 (Ref. 2) noted that support and logistic operations in the Bering Sea will require greater storage capacities for drilling" and production facilities. This will be influenced directly by development of new bases onshore for oil field suppliers, transportation methods and operational philosophies for each field development.

Construction methods developed for onshore and offshore production in the arctic and sub-arctic will influence the design of production facilities. The major influencing factors noted by NPC include:

- components prefabricated in existing facilities on the U.S. West Coast or Far East,

- production facilities constructed in large modules or a single integrated deck to minimize onsite installation and hookup, and

- Sophisticated forward planning for engineering, procurement and fabrication to meet the limited favorable weather periods for offshore installation.

This study assumes multiple production trains over the range of production rates considered. There are cases below, say 60,000 BOPD to 80,000 BOPD, where a single production train might suffice. However, there is an economy in scale where the balance between deck structure and production equipment are optimum.

Production facilities cost and weight are also influenced by drilling requirements and extent of the utilities and quarters. For sub-arctic areas, particularly in the relatively remote Navarin

Basin, platforms will by necessity require greater storage areas and capacity to afford continuous operations. The objective is to increase storage to combat logistical limitations due to weather and remote locations. The requirements to support a drilling operation are more onerous in terms of weight and space.

While single fixed platforms throughout the world possess the capability to process over 500,000 bpd, a sub-arctic deepwater platform will be limited in topside capacity assuming a multi-function (drilling, production, injection, water flood, quarters, power generation, etc.) due to weight and area capacity of the supporting structure. Other restraints include well productivity, drainage area per well, reservoir depth, reservoir shape and other factors such as number of drill rigs, drilling time, type of well {producer or injector), well spacing within platform and safety considerations.

The size and capacity of multi-function topsides facilities are practically limitless, while the supporting structure must be designed for various loadings, including wind, wave, ice, unstable seabed and transportation/installation loads, in addition to those imposed by the topsides. In summary, it might be generalized that as water depth increases, the production capacity decreases. However, experience in the North Sea provides confidence that production capacities can be matched to the discovery size, even in harsh or severe environments. Unstable seabed conditions and seismic considerations in U.S. sub-arctic areas will be further constraints to those encountered in the North Sea.

8.4 Development of Production Facilities Costs

Presented in this section are cost summaries for sub-arctic production facilities. Due to similarities of the various support structure types, these costs are summarized separately for:

- o Bottom-founded structures, including piled fixed jackets, towers, guyed towers and TLP,
- o Floating production systems, including semi-submersibles and monohull type concepts,
- o Subsea production systems,
- o Development drilling, from platforms and subsea.

8.4.1 Platform Production Facilities

The initial emphasis for developing weight, area and cost relationships for topsides facilities was placed upon expanding the NPC data and adding recent historical data for comparably sized North Sea projects. It soon became apparent, however, that historical cost data was not only difficult to obtain, but was also inconsistently reported for the purposes of isolating topsides engineering, fabrication, installation and hookup costs from total project costs. Topsides operating weights (payload) and plan areas were, on the other hand, more readily obtainable. Figure 8-1, which relates topsides operating weight for both modular and integrated deck arrangements, was developed from this historical data.

In order to obtain meaningful cost relationships for the various topsides configurations expected to be considered, a detailed methodology was developed based upon the weight curves shown in Figure 8-1. The resulting cost estimates for a range of scenarios are shown as functions of design oil throughput rate in Figure 8-2.

TOPSIDES WEIGHT
CORRELATIONS FOR THREE BASE CASES
OIL PRODUCTION

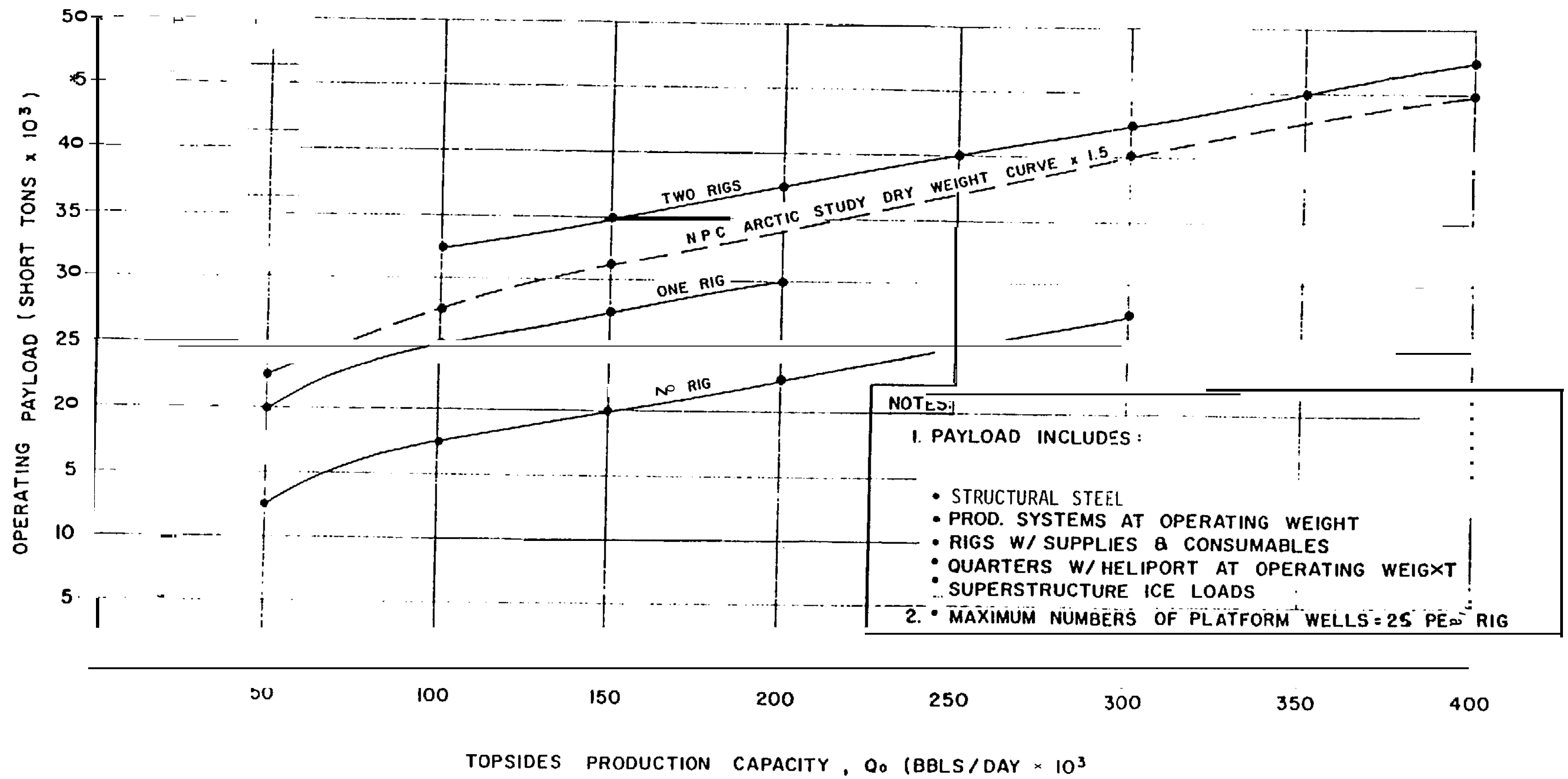
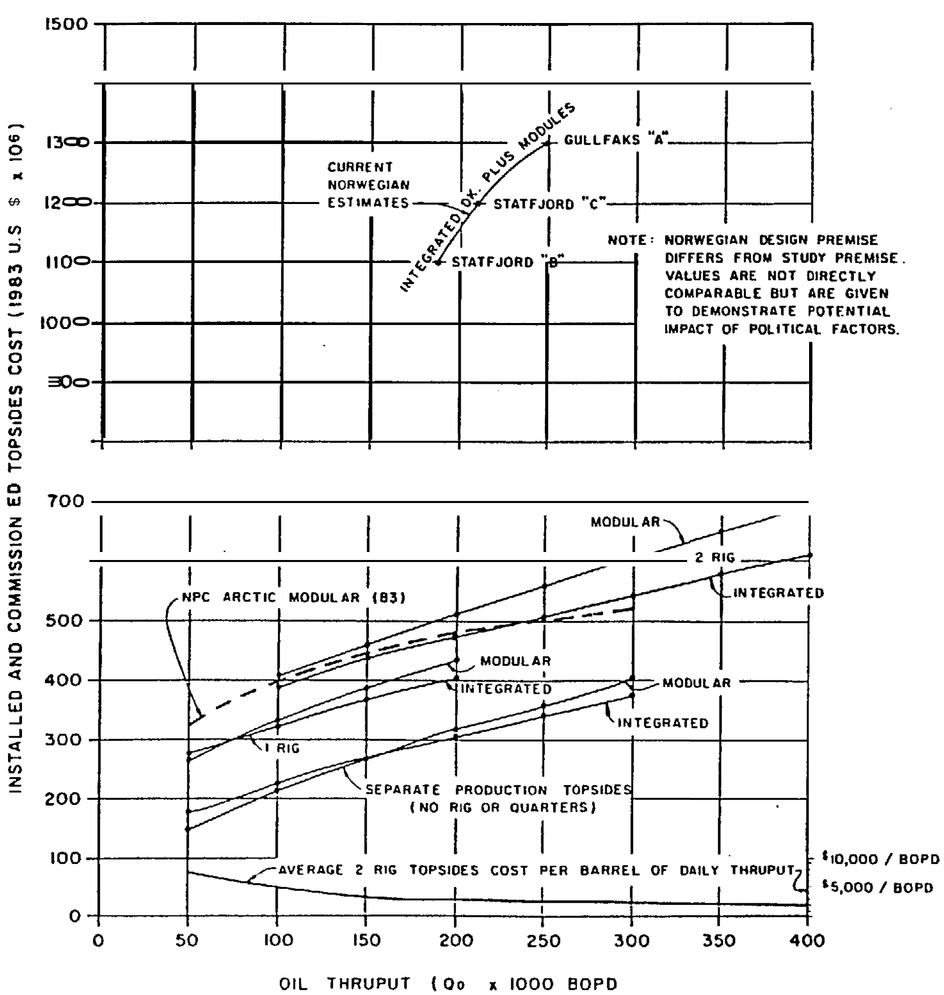


FIGURE 8-1

TOPSIDES COST VS. OIL THRUPUT



INCLUDES:

- CLIENT, PGM, ENGINEER & CONTRACTOR PROJ. MANAGEMENT
- PRELIMINARY & DETAIL ENGINEERING + DESIGN MODELS
- CONSTRUCTION INSURANCE & CERTIFICATION
- DECK & MODULE MATL. & FAB (EXCEPTION: MODULE SUPPORT FRAME WEIGHT & COST HAS BEEN INCLUDED WITH THE JACKET/ TOWER CURVES)
- PROD. EQUIP., BULK MATERIALS, OUTFITTING & PRECOMMISIONING
- DRILLING RIG CAPITAL (UNLESS NOTED)
- QUARTERS (UNLESS NOTED)
- TOPSIDES TRANSPORTATION & SETTING
- TOPSIDES HOOKUP & COMMISSIONING
- COST OF SUPPLIES, CONSUMABLES, FUEL, ETC. NOT INCLUDED

DESIGN PREMISE (OIL CASE)

- WINTERIZED FACILITIES
- SIMULTANEOUS PRODUCTION WHILE DRILLING
- CRUDE: MED. GRAVITY, SWEET,
  NO UNUSUAL PARAFFIN
  WATER CUT = 25%
  GOR = 750 SCF/BBL
- TWO TRAIN, THREE STAGE SEPARATION
- OIL EXPORT TO CAPTIVE STORAGE OR PL. TO SHORE
- WATER INJECTION 120% AT 3000 PSI
- ASSOCIATED GAS INJECTION AT 5000 PSI
- QUARTERS CAPACITY VARIES W/THRUPUT & NO. OF RIGS (SIZE BASED ON 140 SQ. FT PER MAN)
- DNV HELIPORT W/CHOPPER HANGAR & FUELING
- UTILITIES, CRANES, LIFE SUPPORT, ETC AS REQUIRED
- ELECT. PUMPS - TURBINE DRIVEN GENERATORS & COMPRESSORS
- INDEPENDENT DIESEL POWERED RIGS
- CANTILEVERED FLARE BOOM
- AVERAGE PROD. RATE 4000 BOPD PER WELL
- 2 INJECTORS PER 3 PRODUCERS
- MAXIMUM NUMBER OF PLATFORM WELLS = 25 PER RIG. REMAINING PRODUCTION, IF ANY, TO BE PROVIDED FROM SUBSEA WELLS

FIGURE 8-2

Weight Relationships

Weight data obtained for various North Sea topsides facilities varied considerably due to a number of factors, including:

- characteristics of produced fluids
- number of drilling rigs
- design philosophy
- regulatory requirements
- type of support structure
- nominal throughput

Despite the variations, the data showed trends which supported the curves developed in Figure 8-1. The curves as shown do not represent either the high or low sides of the facilities surveyed, but rather a reasonable consensus based upon recent U.K. North Sea experience. (Norwegian topsides were found to be extremely heavy in comparison, due to various unique constraints imposed upon developments in that sector, and were not factored into the resulting curves.) As a sort of check, the topsides dry weight curve contained in the National Petroleum Council's "Arctic Oil and Gas" report has been multiplied by a factor of 1.5 (to convert dry weight to operating weight) and plotted along with the base case and indicates good agreement for essentially comparable facilities.

Cost Relationships

Figure 8-2 shows, in 1983 U.S. dollars, cost functions for integrated and modular topsides for each of three cases (no-rig, one-rig and two-rig installations). These cost curves are based upon the weight relationships shown in Figure 8-1.

8.4.2 Subsea Production Systems

Subsea production systems presently are considered an economical option to platforms or other fixed production facilities under certain conditions. It is anticipated that this feature will be exploited further in hostile environments such as sub-artic areas.

Subsea production systems have been utilized primarily for two areas of application: deep water and marginal fields. A third possible application would be to provide supplemental production in irregular shaped fields where economics might not favor an additional platform, or to locate the more expensive platform in shallower water with the subsea production system placed in deeper water,

Subsea production systems can also be utilized to produce into floating production units (FPS) such as semi-submersibles and monohull vessels.

While their application is usually characteristic of marginal fields (e. g., Hamilton Argyl Field and B.P. Buchan Field), one should anticipate the potential use of large capacity floating production systems as described in other sections of this report.

Currently, there are about 200 subsea wells in 70 fields throughout the world and their use is growing. While there are no applications in water depths greater than 300 meters (1000 ft), this is a result of limited discoveries in deep water. Development plans are in progress, offshore Spain, to install a diverless and guidelineless subsea well head in 760 meters (2,500 ft) of water in the Montanazo Field, connecting it to an existing platform. It is anticipated that when deepwater commercial quantities of oil are found, subsea production systems will deserve serious consideration because of potential technical or economical limitations of deepwater platforms.

Subsea production systems development will require further research, development and testing to meet the requirements of deepwater production. Inaccessibility for maintenance is an inherent disadvantage which can be overcome with the use of high reliability components, redundancy and special maintenance techniques. Special provisions must be made to ensure that failure of a single item does not affect the entire system. Maintenance and troubleshooting operations in deepwater must be designed around special techniques that eliminate the use of divers.

Subsea wells located in clusters and as individual satellites have been utilized throughout the world. Individual field circumstances will dictate the final configuration based on reservoir size and shape, area to be covered, well function (production or water injection), well deviation limits and number of wells.

For this study, extensive use has been made of the Underwater Manifold Center (UMC) Project for the North Central Comorant Field (Ref. 29) This project currently represents the most advanced subsea production system of its kind in terms of size, versatility and sophistication.

The wells are assumed to be arranged similarly to those in Central Coromant Field, with the majority drilled through a cluster or subsea template located away from the production facilities. Individual satellite wells are located away from the cluster. Each satellite well is connected to the cluster by individual flowline bundles. All production from the subsea wells is collected at the manifold located on the cluster and flows through a major flowline bundle to the main production facilities as shown in Figure 8-3. The flowline bundle between the production facilities and the cluster, and lines to each of the satellite wells from the cluster, consist of oil, water, TFL and control lines. All control functions, oil processing and injection water are supplied from the main production facilities.

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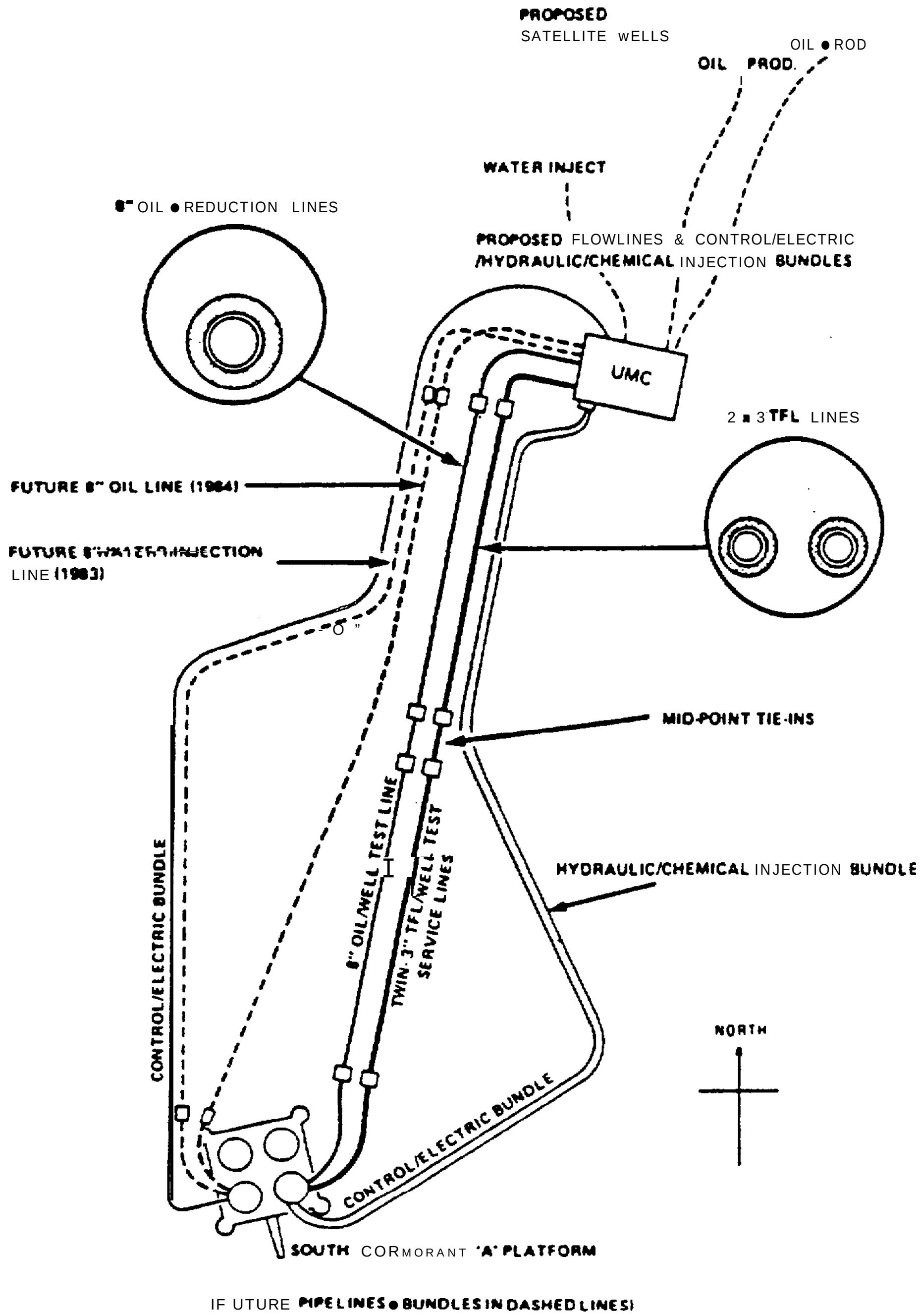


Layout of Central Cormorant UMC pipeline

LAYOUT OF CENTRAL CORM ARANT UMC PIPELINE SYSTEM

FIGURE 8-3

The concept presented for a subsea production system in sub-arctic deepwater areas is summarized as follows:

- Subsea production capacity 50,000 BOPD
- Subsea production injection capacity 60,000 BOPD
- Total number of wells: 27
- Producing Wells: 16 (60%)
- Injection Wells: 11 (40%)
- Cluster Wells: 16(10 producing + 6 injectors)
- Satellite Wells: 11 (producing + 5 injectors)
- Cluster located 7km from Main Production Facilities
- Satellite Wells average 3 km from Cluster

Subsea production system costs and schedules in sub-arctic deep water areas are broken into five (5) main components:

- Cluster or subsea template including manifold, remote maintenance vehicle, engineering construction, testing and installation.
- Flowline bundle from clusterto main platforms orFPS.
- Satellite Cost
- Flowline from each satellite to cluster.
- Drilling Costs

Figure 8-4 presents the costs for the above components. Drilling costs are presented in Section 8.4.4.

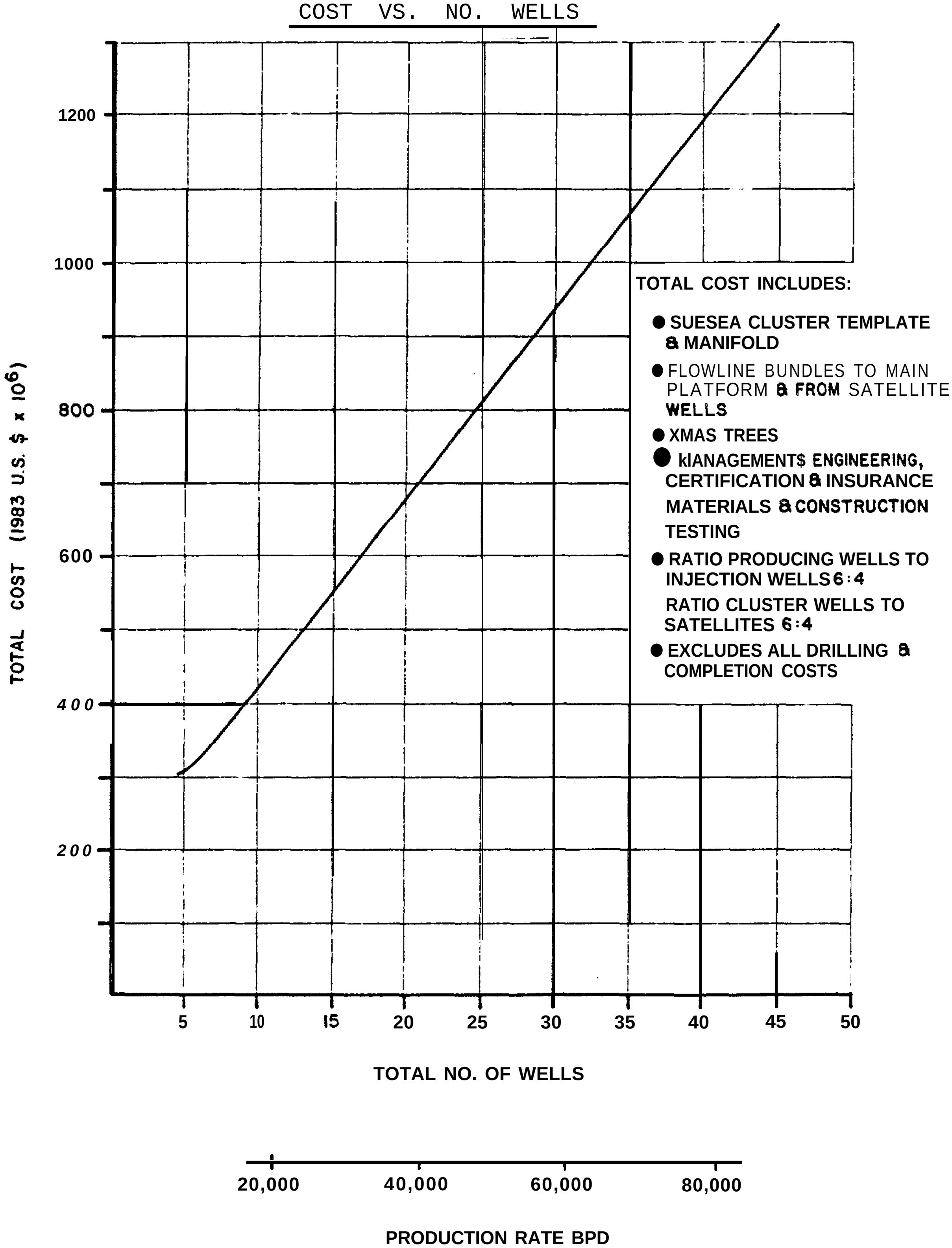
8.4.3 Platform Development Drilling

Development drilling for sub-arctic areas will require winterized rigs similar to those presently being used for onshore development drilling and offshore exploratory drilling in Alaska. These drilling rigs are partially enclosed and heated to provide a comfortable working environment for personnel to provide safe and

FIGURE 8-4

SUBSEA PRODUCTION SYSTEM

COST VS. NO. WELLS



efficient working conditions. Special consideration is also given to covered storage areas and freeze protection during cold periods to allow year-round drilling operations.

Twin rigs will be utilized on platforms to facilitate a drilling program of four (4) to five (5) years.

Costs were developed from data in References 24, 25, 26 and 2. Logistics and resupply costs were the principal cost variable between the three (3) regions considered in this study.

The primary factors in supply and logistics hinge on supply base locations relative to the drilling location and transportation methods employed (Ref. 1, 13, 16, & 18). The distance between the land base and Navarin COST Well drilled in 1983 resulted in crew changes by specially equipped long range helicopters that could fly the total round-trip distance of almost 1,450 kilometers (900 mi) without refueling. In addition, another helicopter is stationed on the semi-submersible drilling rig as a medical evacuation aircraft (Ref. 30).

The cost of an extended range helicopter capable of this distance is in excess of $9 million. The nearest deep water port is about 725 kilometers (450 mi) away. The operating expense of helicopters and supply boats may be as high as $15 million to $25 million annually.

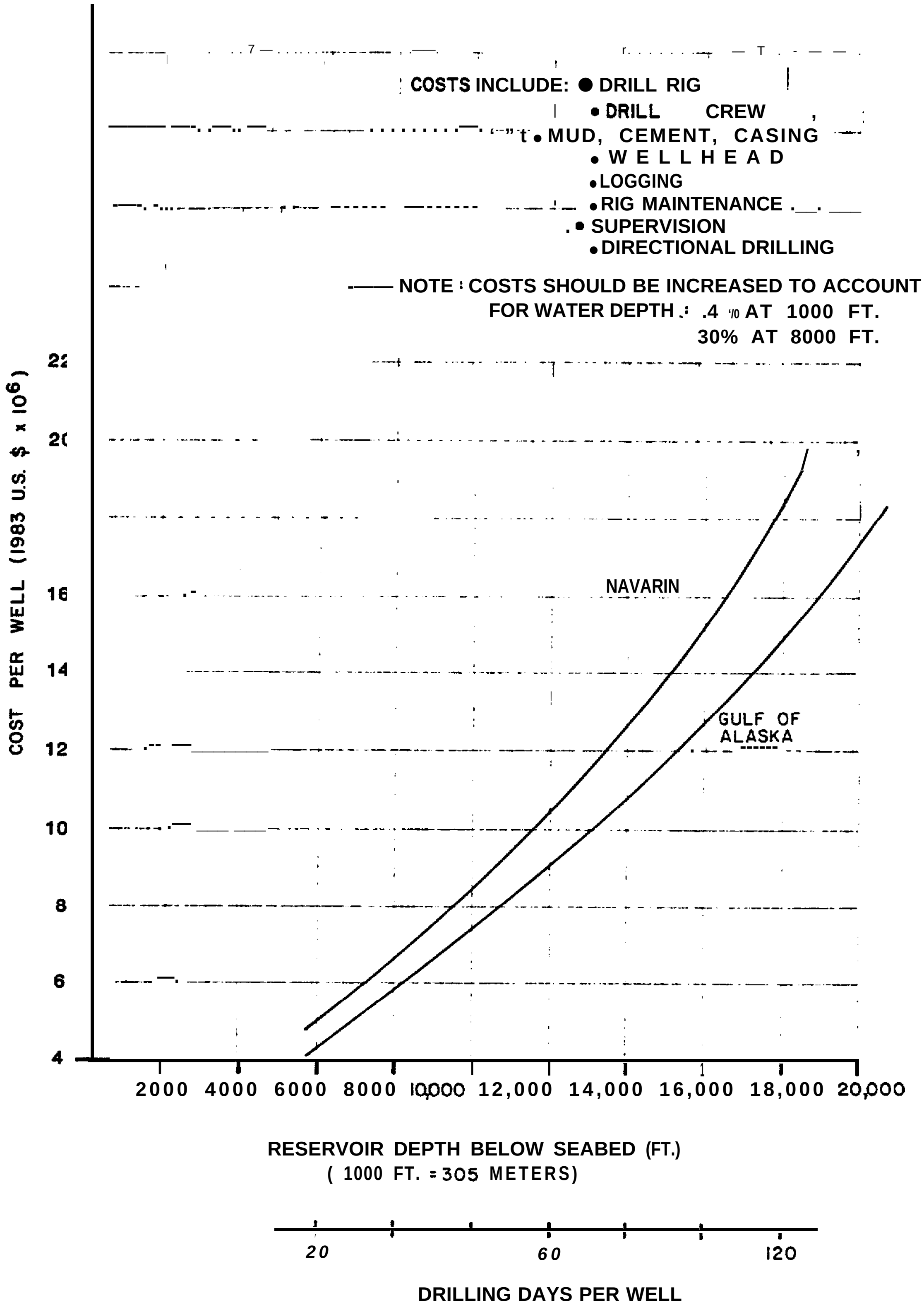
In the event of a commercial discovery, the conversion of delineation wells to development wells is worthy of consideration because of the anticipated cost of each well drilled subsea. While this conversion aspect has not been estimated, the anticipated costs of connecting satellite subsea wells is presented in Sections 8.0 and 9.0.

Development well costs are presented in Figure 8-5 for the three (3) study regions.

FIGURE 8-5

PLATFORM DEVELOPMENT WELL COSTS

ALASKAN SUB-ARCTIC O.C.S.



8.4.4 Subsea Development Drilling

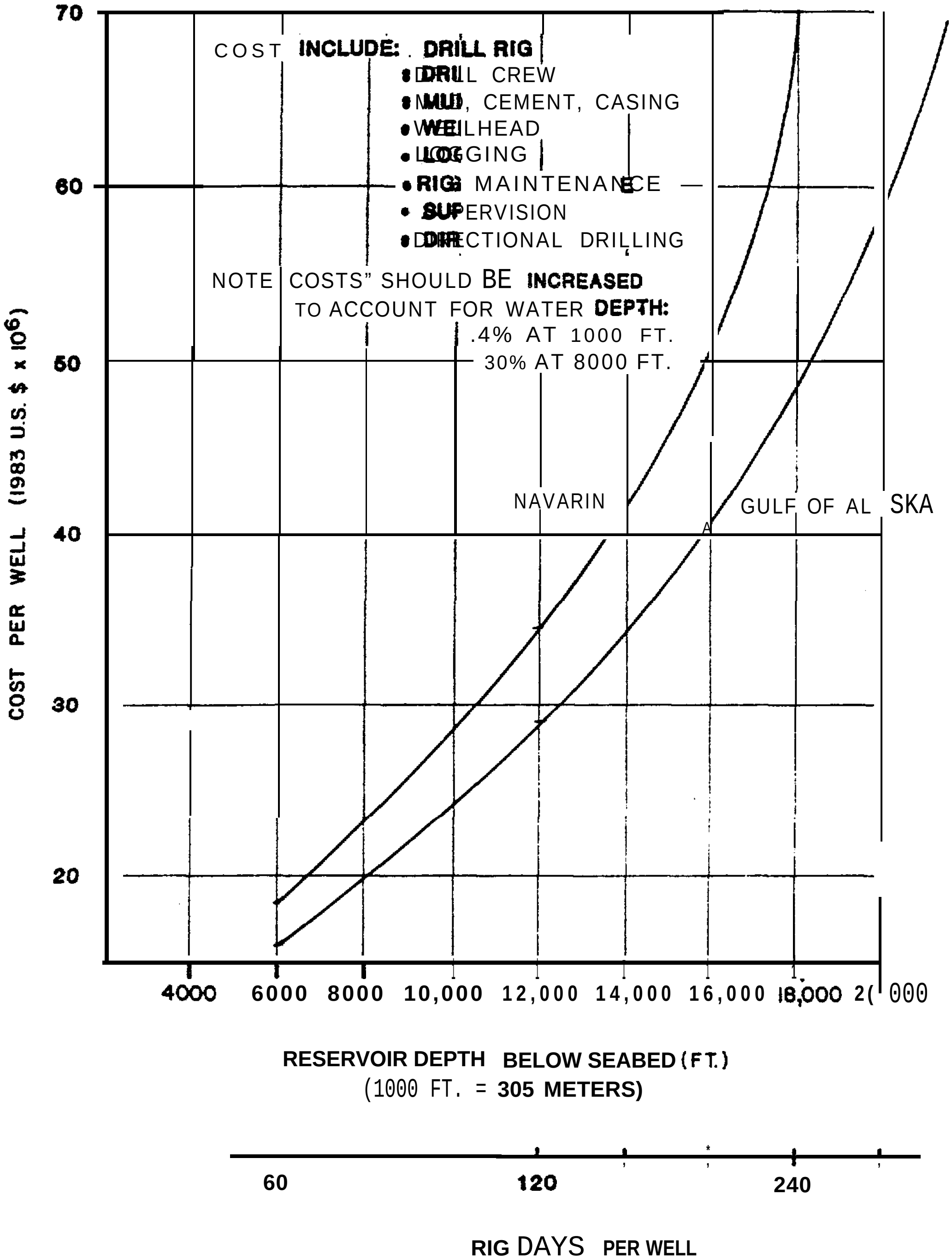
Subsea development drilling has been developed throughout the world to produce almost 200 subsea wells in 70 different fields. In addition, a significant number of wells have been predrilled through a subsea template prior to placement of a fixed structure over these predrilled wells. In this case, the wells were tied back to the platform and completed in a short period by the platform rig to achieve early production. For deep water sub-arctic areas, this study assumes that the high costs of subsea development wells will probably limit their use to supplemental production to fixed platforms and production to floating production systems (FPS). The economics of specific field conditions will need to be considered to assess the merit of predrilling wells prior to fixed platform placement to achieve early production. Another major point toward improving field development economics should also consider recompletion and production from discovery and appraisal wells to recover some of the original exploratory investment.

Subsea development well costs were extrapolated from exploratory well costs in Subsection 6.4 by making allowances for additional completion expenses and material costs. These costs are presented in Figure 8-6. Costs for the drilling templates, wells and associated hardware are included in the subsea production system costs.

FIGURE 8-6

SUB SEA DEVELOPMENT WELL COST

ALASKAN SUBARCTIC O.C. S.



9.0 ASSUMPTIONS FOR TRANSPORTATION SYSTEM COSTS

9.1 Introduction

Transportation of crude oil from fields in all of the areas of interest in the Alaskan sub-arctic will be greatly influenced by the very long distances to shore, but even more so by the lack of a refinery or an existing terminal and storage facil ity at the landfall. Thus, an onshore tank farm with a near-shore loading terminal would be required at the end of a very long pipeline to offload the crude into tankers for final delivery to market.

Offshore storage and loading systems provide an alternative to the very expensive long pipeline/grassroots onshore terminal approach, especially in the early stages of frontier development before shared pipeline networks are established.

The components of a typical offshore storage and loading system (see Figure 9-1) consist of:

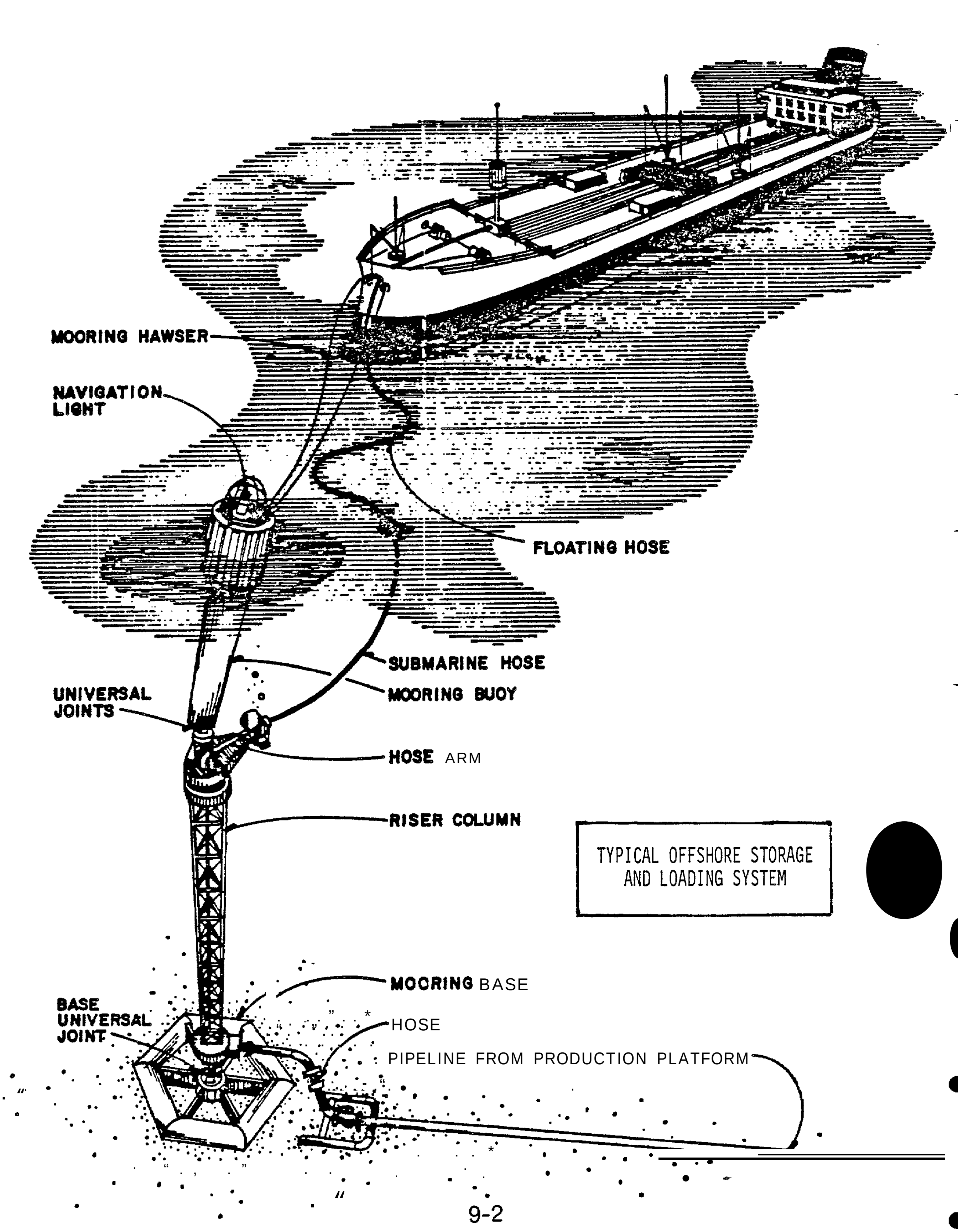
- A short crude export pipeline,
- The mooring fora captive storage tanker, and
- The storage tanker.

Existing offshore storage and loading systems handle field production rates approachi ng 300,000 BOPD. Sati sfactory performance has evolved in even the very hostile environment of the Northern North Sea; however, all the existing systems are in ice-free regions.

Included in this section are the relevant experience and cost data from the construction, operation and support of offshore transportation systems in mature provinces. Factors which will significantly influence the application of the ready technology to the deepwater sub-arct· c are discussed, and the resulting cost estimates are provided.

SINGLE ANCHOR LEG MOORING "SALM"

FIGURE 9-1



9.2 References

The collective experience of the project team encompasses considerable direct participation in the evolution and practice of today's deepwater pipeline technology. Recent original work for a similar study provided raw cost data appropriate for remote pipeline construction in hostile environments.

A recent proprietary survey of existing offshore loading systems, as well as OTC papers over the last decade and in-house direct involvement in the installation of some of the systems provide insight into the unique characteristics and performance of the multitude of offshore loading concepts.

Extensive use was made of the data supporting the NPC "U.S. Arctic Oil and Gas Survey Report" (Ref. 2) for onshore storage. This data includes the existing storage facilities at both ends of the Trans-Alaska Pipeline; however, the requirements envisaged for this study would be of substantially reduced scope.

Logistics references abound throughout this report, further demonstrating the widespread impact of this influence.

9.3 Influencing Factors for the Sub-Arctic Transportation Systems

The basins of study interest may all be characterized as remote and hostile - but mostly ice-free. Of these three major influencing factors, remoteness will produce the greatest impact by eliminating pipelines as economic alternatives in most scenarios.

9.3.1 Mainline Marine Pipelines

Thousands of miles of marine pipelines have been laid in the last 30 years of intense offshore activity. Pipelines have been i nstal led in water depths exceeding 600 meters (approx.2,000 feet). Lines as large as 56 inches in diameter have been laid in *shallower* depths. Pipeline projects have been successfully completed in harsh environments such as the Northern North Sea, Australia, New Zealand and Tierra del Fuego; however, equipment and methods are continuing to be refined. Frontier projects have been completed in the operationally remote areas of the Far East.

Conventional pipelay procedures and equipment, with enhanced mooring systems and dynamic positioning assistance are ready for commercial application in 450-meter (approx. 1,500 ft) depths. Systematic allocation and familiarity with these advance station-keeping systems should provide the experience and confidence to install 20-24 inch diameter pipelines in up to 1,000 meters (approx. 3,300 ft) of water. Single-station advanced welding systems (such as laser, election-beam and friction welding techniques) are presently under development and hold a great potential for reducing the cost of marine pipeline installation in moderate depths by significantly increasing the speed of pipelay operations. Such systems will also allow steeper angles of pieline entry into the water thereby eliminating one of the major constraints to economic deepwater pipeline construction for large diameter lines,

Some Alaskan sub-antic offshore areas are threatened by the movement of large ice ridges and small icebergs through locals where pipelines may need to be installed. One proposed solution to this potential hazard is to trench the pipeline into the seabed to a depth that would allow the keel of the iceberg to either harmlessly plow through the soil above line or to become grounded before reaching the line. Current pipeline tranching technology limits single-pass trenching capabilities to ditch depths of approximately

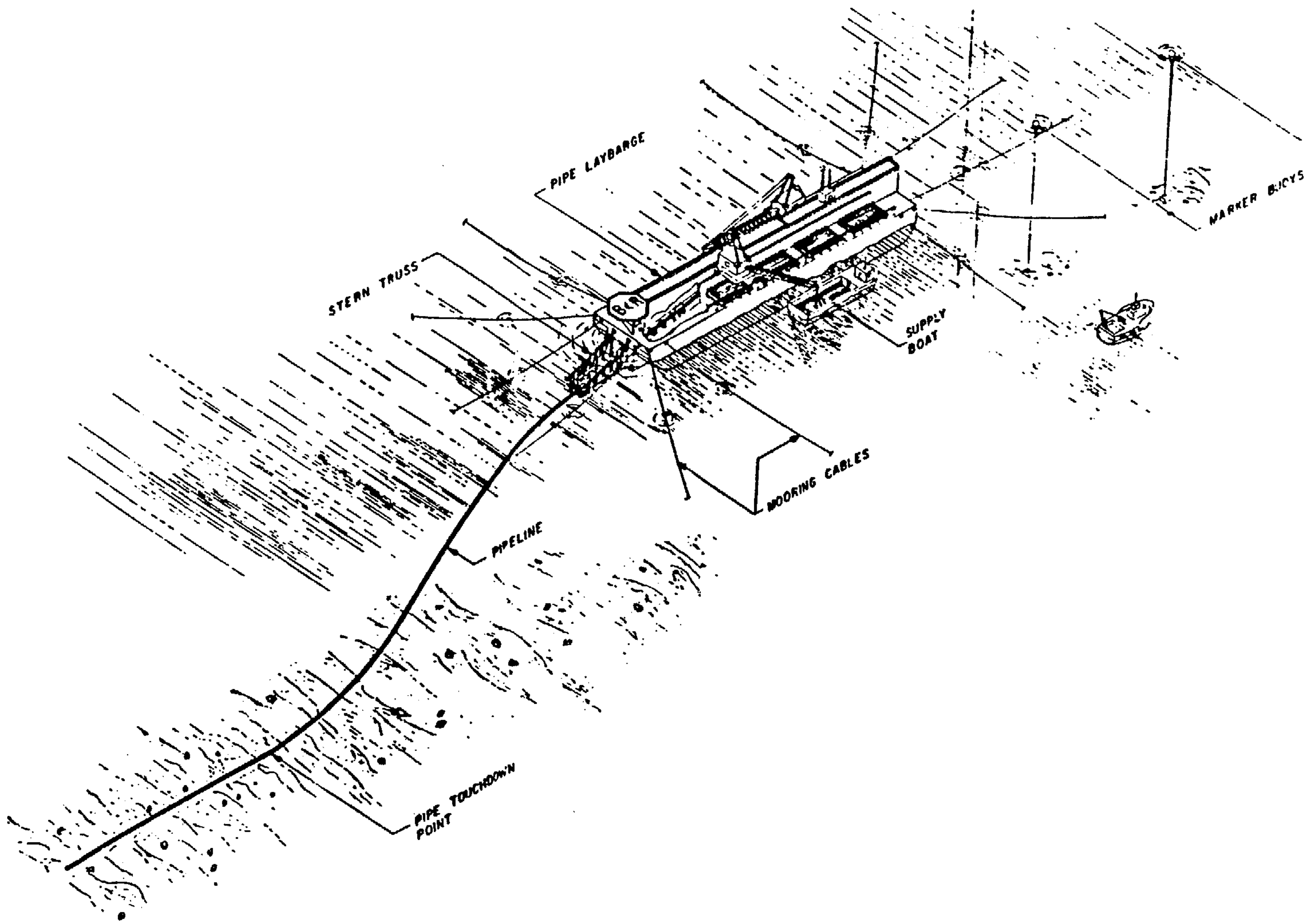
3-4 meters (approx. 9 to 12 ft) at a cost ranging from $250,000 to $500,000 per mile. It is possible that a significant length of pipeline may need to be trenched only for the purpose of mitigating the iceberg hazard, while no assurance of absolute protection is achievable. On the other hand, the replacement of a damaged segment of pipeline would be in the $5.0 - 6.0 million range. Recent hyperbaric pipeline repairs have been successfully completed in 300 meters (approx. 1000 ft) of water. Mechanical connector repair operations are also fess ble for depths approaching 450 meters (approx. 1,500 ft), with the potential for extension of repair operations beyond diver depths through the development of surface-operated mechanical repair systems and more powerful and more mobile Remote Operation Vehicles (ROVs).

Pipelines are influenced by production throughput and length. Besides being a direct multiplier of cost, length will govern line size and pressure drop as well as be the major variable in the determination of the need for intermediate booster pump platforms. It is generally agreed that submarine crude pipelines requiring intermediate pump platforms are not an economic alternative. Accordingly, pump platform costs have not been included.

Pipeline installation techniques and costs are influenced by water depth, but technology does not appear to be a limiting factor for small lines in water depths up to 2,000 meters (approx. 6,500 ft).

A variety of optional construction techniques and equipment may be used to install marine pipelines, depending upon project requirements. Included are the conventional lay-vessel method, the reel-vessel method, and various tow and bottom-pull methods.

The characteristics of the area of study interest would favor the lay-vessel method, because segment transit time and the multitude of complex segment tie-in operations associated with the alternative methods become prohibitive for large long lines. Figure 9-2 illustrates typical pipelay operations.



PIPELINE LAYING OPERATION

FIGURE 9-2

The use of less weather-sensitive semi-submersible lay barges is envisaged for all of the study areas. Dynamic positioning. will be required in over 300-meter (approx. 1,000 ft) depths to supplement conventional moorings. Complete dynamic positioning will be required beyond 1,000 meters (approx. 3,300 ft).

The construction weather-window on the Alaskan sub-arctic will determine the number of years required for construction or dictate the number of construction spreads at work during one season. A. construction season of 6 to 8 months has been assumed for this study. Remoteness will influence the number of boats supplying pipe to the laybarge and helicopter range requirements; however, this impact on the cost of a large, long line would not be realistically identifiable due to the relative coarseness of the costing method.

Burial of a pipeline along its entire length appears unnecessary; however, burial through the shore approach (shoreward of the 5-6m contour) is mandated by OCS Orders.

9.3.2 Infield Pipelines and Flowlines

Pipelines between fixed/floating platforms and to offshore storage and loading facilities are a requirement for most development scenarios. For convenience, the influences and costs associated with storage and loading pipelines have been incorporated into the coverage of such systems in other sections of this report. The influences and costs associated with pipelines between platforms are similar to those for flowline bundles; however, they provide ony a single service function - comingled production transport - resulting in considerably less complexity. Installed costs for infield flow lines up to 16 kilometers (1 0 miles) in length - may be estimated by factoring mainline laying costs to account for losses in pipelay efficiency associated with short lines.

Satellite subsea wellheads are incorporated into the production system with a multi-function flowline bundle typically consisting of:

- o Twin production/service lines
- o Hydraulic control lines
- o Chemical injection lines
- o Electrical Control Cables (optional)

The service lines provide for production, test, TFL entry and return, and well kill functions. These lines may need to be insulated to reduce heat loss to the sea, to prevent increases in fluid viscosity and/or precipitation of hydrates.

Flowline bundle requirements from multi-well templates (Underwater Manifold Center-UMC) are greater in complexity as well as capacity. Provisions for additional functions such as comingled production, water injection and gas lift/injection may be required.

Flowline bundles are relatively short--16 kilometers maximum (10 miles)--and are very compatible with shore assembly/string tow construction methods in less remote and milder environments. Sub-arctic bundles will most probably be installed by laybarges (and less likely by reel barges).

9.3.3 Captive Tanker Storage and Loading Systems

A practical means for providing storage on an offshore lease is to use a floating storage vessel. Oil from the platform flows through a short pipeline and riser into the storage vessel. Shuttle tankers can be loaded directly from the storage vessel to take the oil to market.

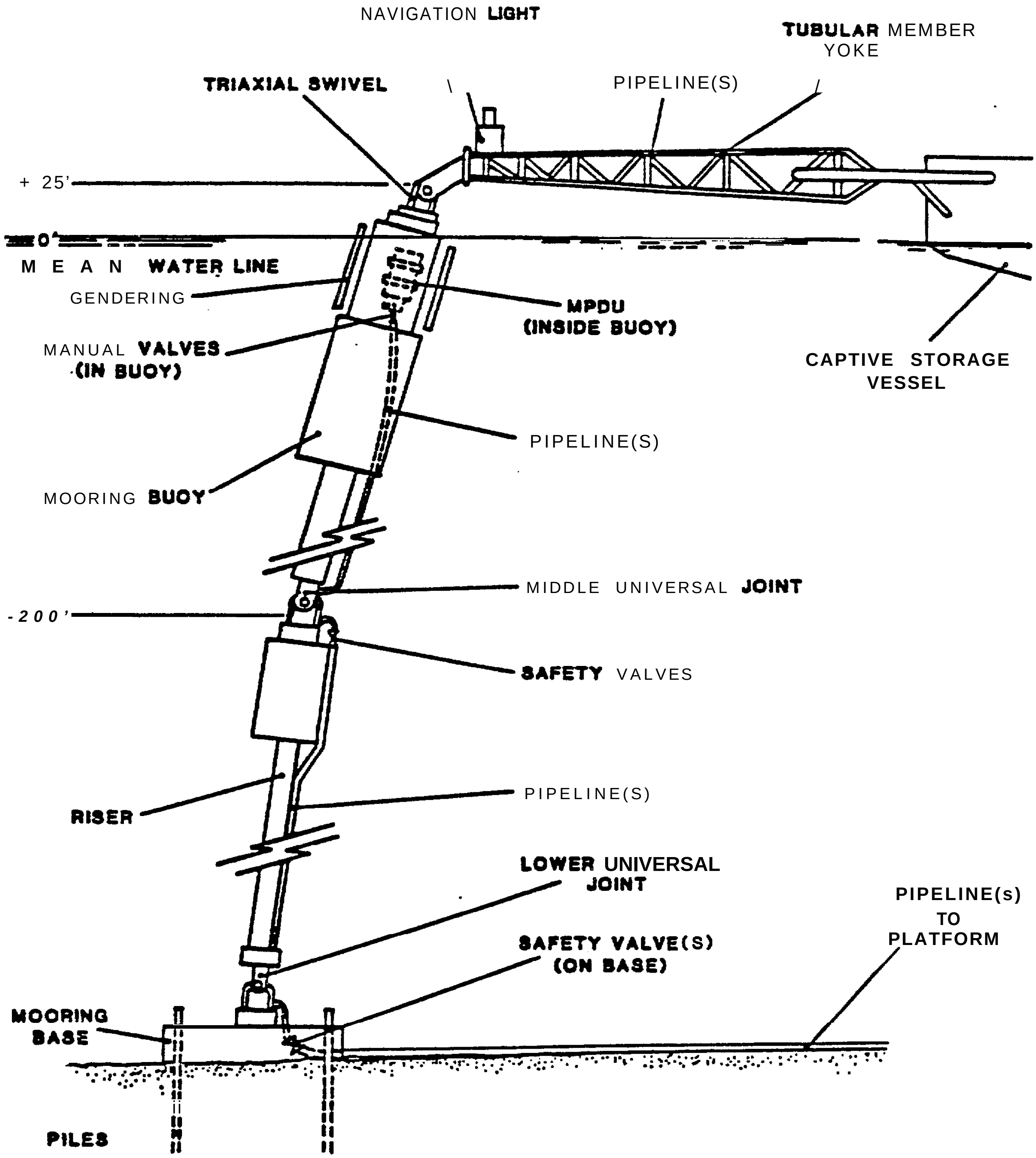
The captive storage mooring system (Figure 9-3) consists of:

- o A base unit to provide the anchorage,
- o A riser element to transmit the mooring forces and provide an oil conduit, and
- o A surface buoy/swivel/yoke unit that completes the flowpath and provides the connection to the tanker while allowing the tanker to weathervane around the mooring to seek the most advantageous orientation to wind, waves and current.

Many variations of the system exist reflecting evolving technology and operational feedback from existing systems in up to 200-meter (approx. 660 ft) depths. Today's technology appears satisfactory for depths approaching 1,000 meters (approx. 3,300 ft). Conceptual speculations for up to 2,000-meter (approx. 6,600 ft) depths are in the developmental and model testing stages.

The principal influence on the cost of a captive storage system is the size of the storage tanker. The daily production rate and the number of days of storage to be provided are primary variables. Tankers themselves may not be a significant cost element today, as they exist in oversupply, and some sizes can be acquired at their scrap value. Modification is necessary to suit offshore mooring and loading requirements, especially to accommodate ice loads by strengthening the tanker hull and adding strength to the mooring system.

The mooring system and pipeline riser are the major cost components of this system in the study area. The storage tanker must remain on station to prevent shut-in of the field. The extreme environmental conditions, water depths and tanker sizes to be expected in deepwater sub-arctic scenarios produce significant combined requirements.



CAPTIVE STORAGE MOORING SYSTEM

FIGURE 9-3

The pipeline from the platform is sized for the daily production rate; however, the line is rather short - 3 to 5 kilometers (2-3 miles) - and the cost of mobilization and installation tends to overwhelm the cost of materials, such that the influence of line size is supressed.

9.3.4 Articulated Storage Towers and Loading Systems

The articulated storage tower concept is envisaged to replace the mooring riser and storage tanker functions in the previous sytem for some deepwater applications. A purpose-build storage column is connected by a universal joint to the mooring base as shown in Figure 9-4. The large displacement of the column provides the righting moment to counteract wave forces on the unit as well as the pull of the shuttle tanker when loading directly from the unit. A large turntable-at the top of the column allows the shuttle tanker to weathervane around the unit, in some ways similar to the alternative systems.

The existing articulated storage tower installation in the Beryl field in the North Sea has experienced greater than expected mechanical problems with the universal joint, but experience with present systems is leading to solutions to these types of problems.

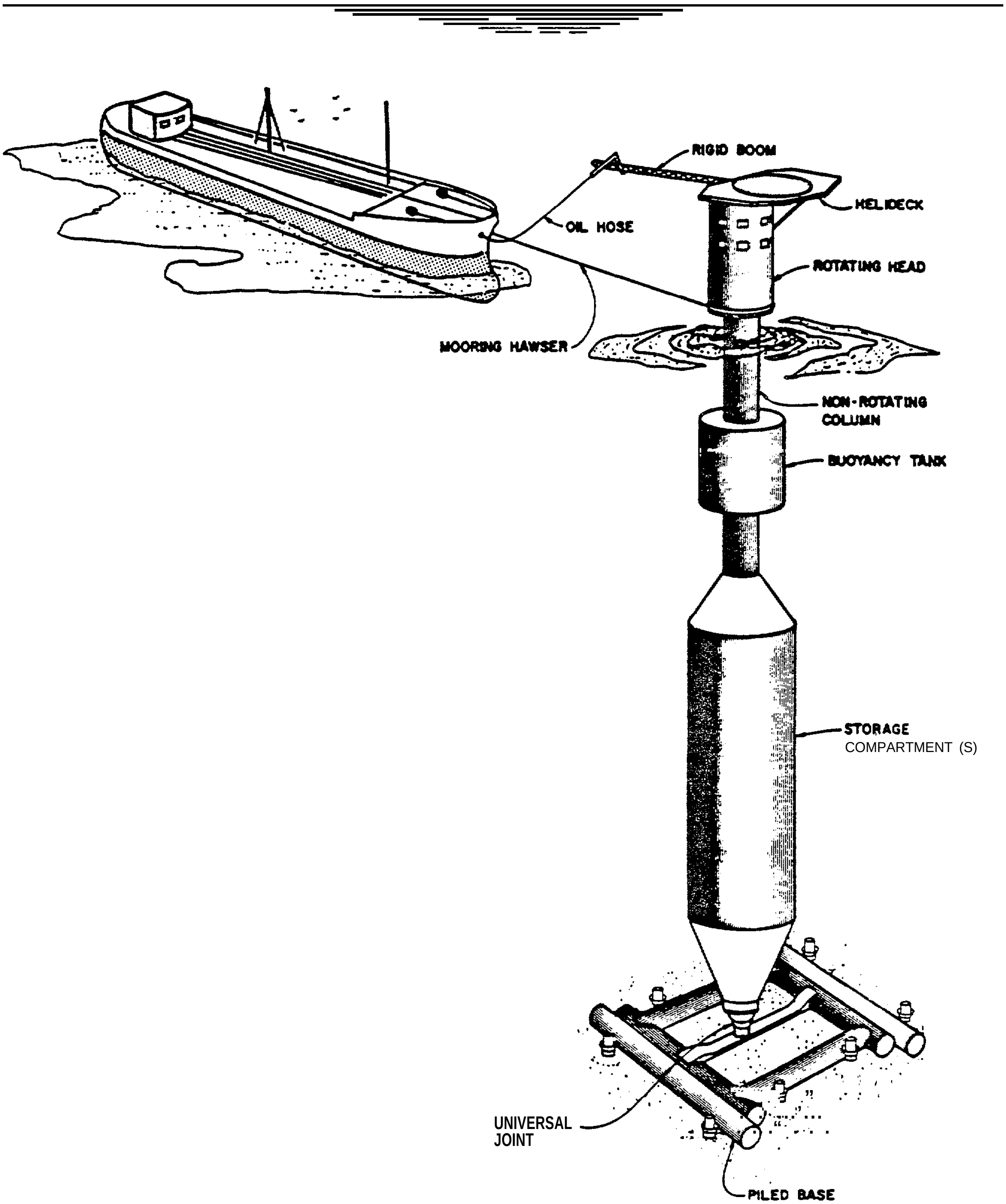
Although the concept shows some promise for utilization in remote deepwater applications, today's economics favor converted tanker captive storage systems on the basis of low cost and immediate availability. Costs for the Articulated Storage Tower concept have not been presented.

9.3.5 Onshore Terminals

As discussed previously, offshore storage and loading systems provide adequate and cost-effective alternatives to onshore terminals for remote frontier developments. As development operations in the basins of interest mature, shared mainline

FIGURE 9-4

ARTICULATED STORAGE TOWER



pipelines to shore and onshore storage and loading terminals may evolve, as the economies of scale associated with such facilities influence the decision-making on later projects. Established production in each basin may need to reach threshhold rates of between 500,000 and 1,000,000 BOPD to overcome the large fixed costs for civil improvements, pipework, camp, maritime support and loading berths.

The capital and operating costs reported in the NPC U.S. Arctic Oil & Gas Survey Report are appropriate for the coarse economic assessments made prior to full scale exploration activities, and will not be repeated here so as to avoid misrepresenting their basis through oversimplification.

9.3.6 Logistics and Supply Facilities

This study presumes the existence of an onshore petroleum infrastructure from pre-existing shallow water field developments and does not present capital or operating costs for these facilities as these have been addressed in previous studies - namely, Reference 2. Deepwater exploration, production and transportation will add to the requirements of these facilities in terms of harbor depth and drydocking facilities for the larger support craft as well as the additional volumes of supplies and materials consumed by the expansion of operations into deeper water.

The incremental costs resulting from the increased logistics requirements associated with deepwater operations have been incorporated directly into the costs for the deepwater systems and components.

9.4 Cost Summary for Transportation Systems

Cost curves are presented in this section for remote subsea pipeline construction and for captive storage and loading systems. As noted in Section 9.1, the captive storage and loading scenario will probably be more feasible than a pipeline to shore for initial deepwater developments on the Alaska Sub-arctic O.C.S.

9.4.1 Pipelines

The following cost curves are included at the end of this subsection:

Figure 9-5, Oil Pipeline Sizing -Mainline to Shore
Figure 9-6, Mainline Pipeline Cost and Schedule
Figure 9-7, Infield Pipeline Cost and Schedule
Figure 9-8, Pipeline Riser Cost and Schedule
Figure 9-9, Pipeline Shore Approach Cost and Schedule
Figure 9-10, Pipeline Bury Cost and Schedule
Figure 9-11, Pipeline Repair Cost

From these curves total pipeline costs, including risers and shore approach, may be estimated for water depths up to 915 meters (3,000 ft), diameters to 36", and various soil conditions. A schedule showing average number of miles achievable per weather window for various pipeline sizes and water depths is included in Figure 9-6.

The following example will serve to illustrate use of these curves:

Oil Production Rate	200,000 BOPD
Distance From Shore	160 km (100 miles)
Water Depth	305 m (1,000 ft)
Shore Approach Length	915 m (3,000 ft)
Type of Soil	#2 (Granular and Medium Clays)
Depth of Trench	2.8 m (9 ft)

step 1 - From Figure 9-5, determine nominal pipeline diameter for 200,000 BOPD and 160 km (100 mi) length: 24".

Step 2 - From Figure 9-6, determine installed cost of pipeline, excluding *riser,* trenching, and shore approach, for 24" pipeline installed in 305-meter (1,000 ft) water depth: $42,000/mile/inch of nominal diameter, or $100.8 million, + MOB & DEMOB cost (one spread for one weather window) of $10 million. Total cost: $110.8 million.

Step 3 - From Figure 9-8, determine installed cost of 24" pipeline riser in 305 meter (1,000 ft) water depth: $3.4 million.

Step 4 - From Figure 9-9, determine cost for 915 meter (3,000 ft) shore approach using digging method: $2.12 million.

Step 5- (Optional) From Figure 9-10, determine trenching/burial cost for 2.8-meter (9 ft) trench and soil type 2: $33.00 per linear foot of trench, or $174.2 million, + MOB & DEMOB cost (one spread for *one* weather window) of $5.4 million. Total cost: $179. 6 million.

Step 6- Add costs from Steps 2 through 6 to get total installed cost, including riser, tranching, and shore approach:

Installation By Lay Barge	$11 O.8X 10^6
Pipeline Riser	3.4
Shore Approach	2.1
Trenching/Burial	179.6 (as required)
Total Installed Cost	$295.9 $\times 10^6$
Estimated Cost - Per Kilometer	$1.86 million
- Per Mile	$3.0 million

It must be noted that the pipeline length does not warrant intermediate pump platforms in this example. For longer pipeline lengths the cost of an offshore pump facility could double the total installed cost. The resultant cost would approach those determined by NPC in Reference 2. For this reason pipelines to shore terminals, requiring lengths of 320 to 640 km (200 to 400mi), were not considered viable in this study.

9.4.2 Captive Tanker Storage and Loading Systems

The following cost curves are included in this subsection:

Figure 9-12 Captive Tanker Storage Cost
Figure 9-13 Captive Tanker Mooring and Infield Pipeline Cost

Construction schedules are also shown on these curves.

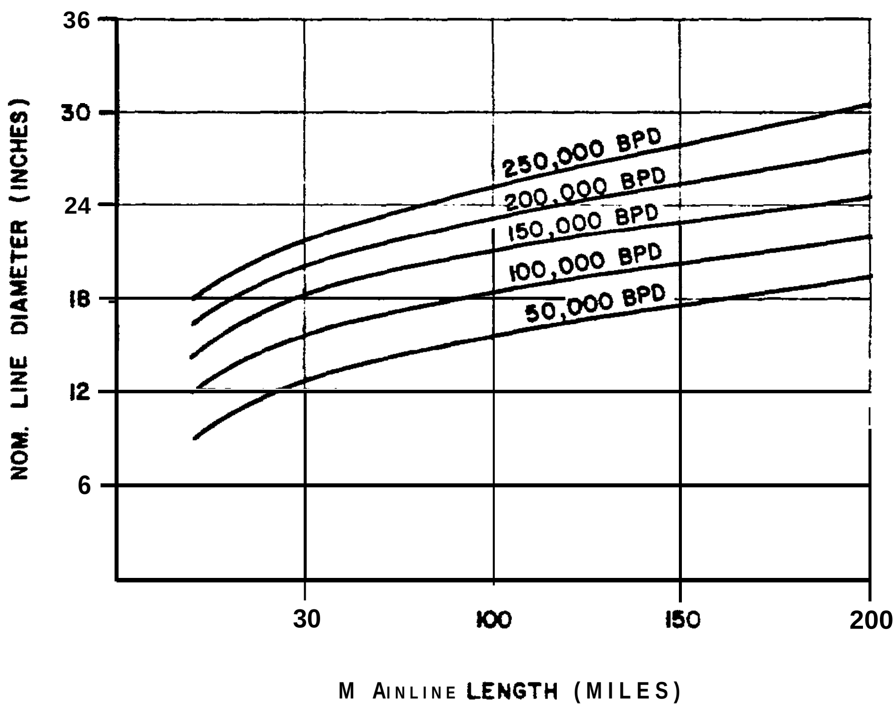
The following example shows the cost for a captive tanker storage and loading system to handle the same quantity of oil used in the pipeline case example shown on the Subsection 9.4.1.

Oil Production Rate	200,000 BOPD
Water Depth	305 m (1,000 ft)

Step 1 - From Figure 9-12, determine cost of converting an existing tanker to hold five (5) days production, or 1,000,000 barrels: $15 million.

Step 2 - From Figure 9-13, determine cost of mooring the captive tanker and installing the infield pipeline, riser, SALM, etc., in 305-meter (1,000 ft) water depth: $65 million.

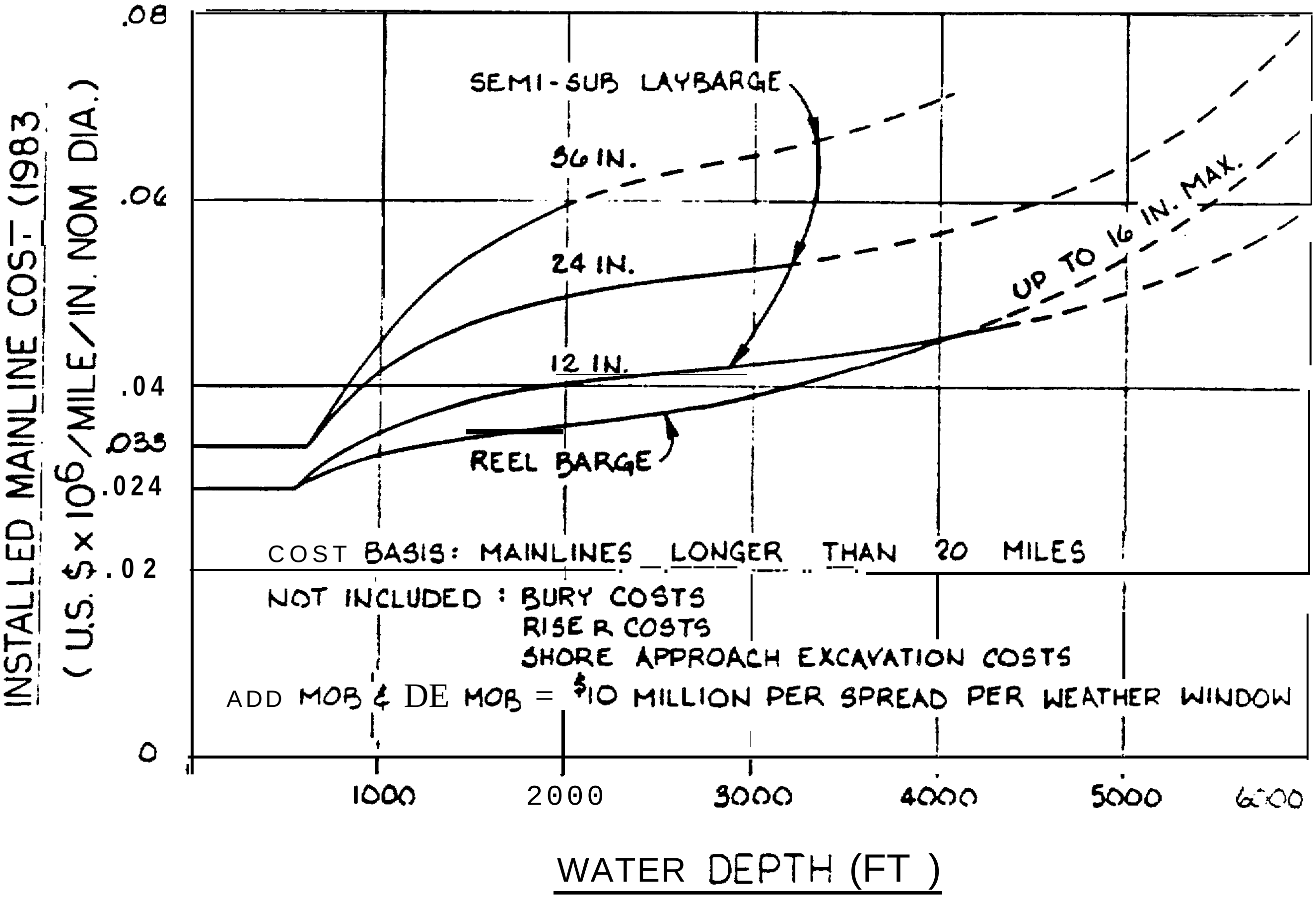
Step 3 - Add costs of Steps 1 and 2 to get total installed cost: $80 million.



OIL CASE : ANSI CLASS 600 SYSTEM
INLET PRESSURE 1480 psig
PRESSURE AT LANDFALL 250 psig
26° API CRUDE

FIGURE 9-5

OIL PIPELINE SIZING



COSTS INCLUDE :

- PROJECT MANAGEMENT DESIGN, CERT. & CONSTR. INSURANCE
- PIPE COATINGS, BUCKLE ARRESTORS, ANODES, ETC.
- PRE & POST SURVEYS & BARGE ALIGNMENT
- HAUL, WELD, LAY, X-RAY & TEST
- NORMAL WEATHER DELAYS DURING WEATHER WINDOW

SCHEDULE

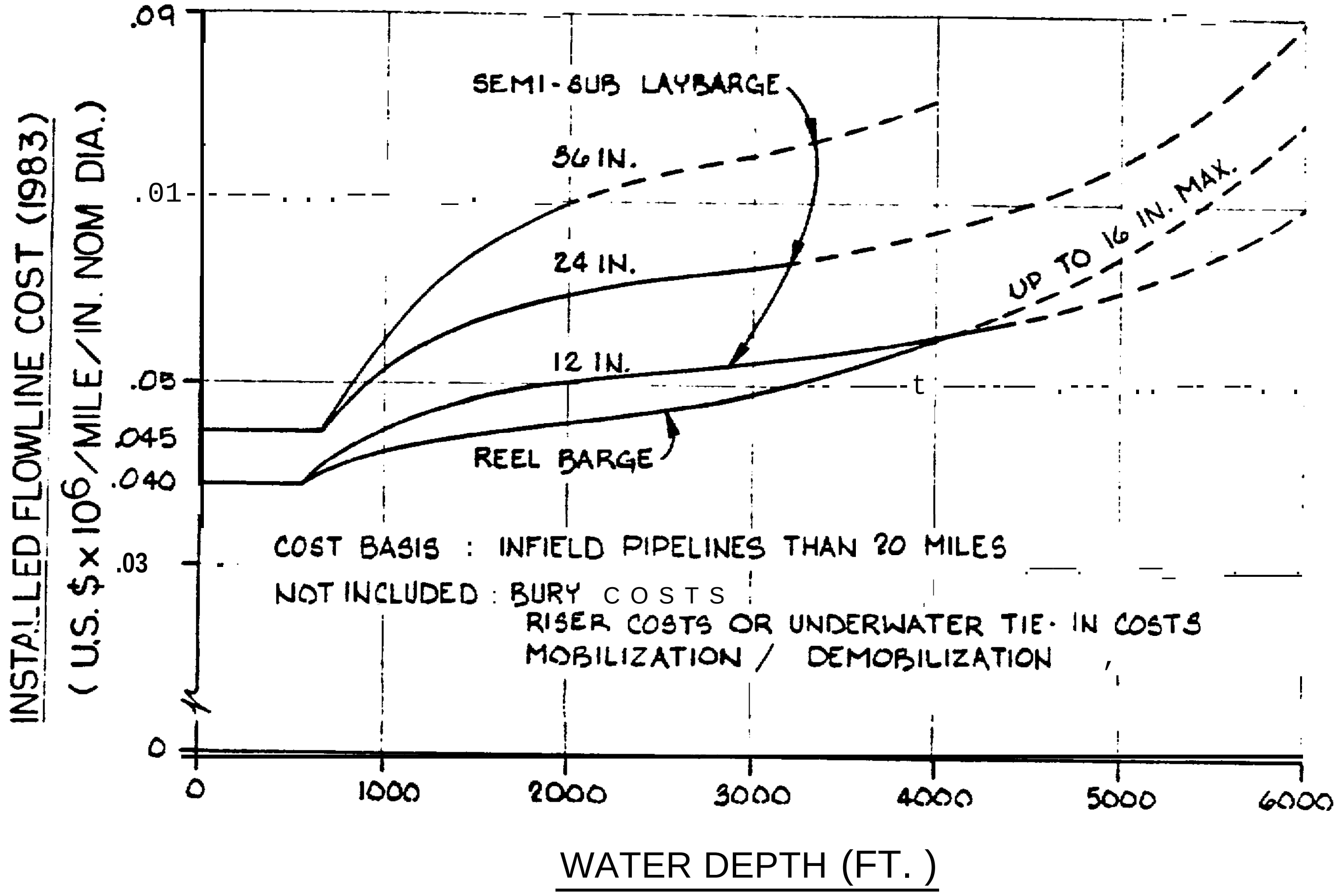
AVERAGE MILES PER WEATHER WINDOW (240 DAY WEATHER WINDOW)

SIZE	1000'	2000'	3000'
12"	300	290	280
24"	270	220	210
36"	200	120	110

ALLOW:
12 MOS. DESIGN
1 2 MOS. PIPE COAT & MOB
ADD 12 MOS. / WEATHER WINDOW
Of? ADDITIONAL SPREADS
AS REQ'D + 3 MOS. FOR TEST, ETC.

MAINLINE **PIPELINE** COST & SCHEDULE

FIGURE 9-8



COSTS INCLUDE :

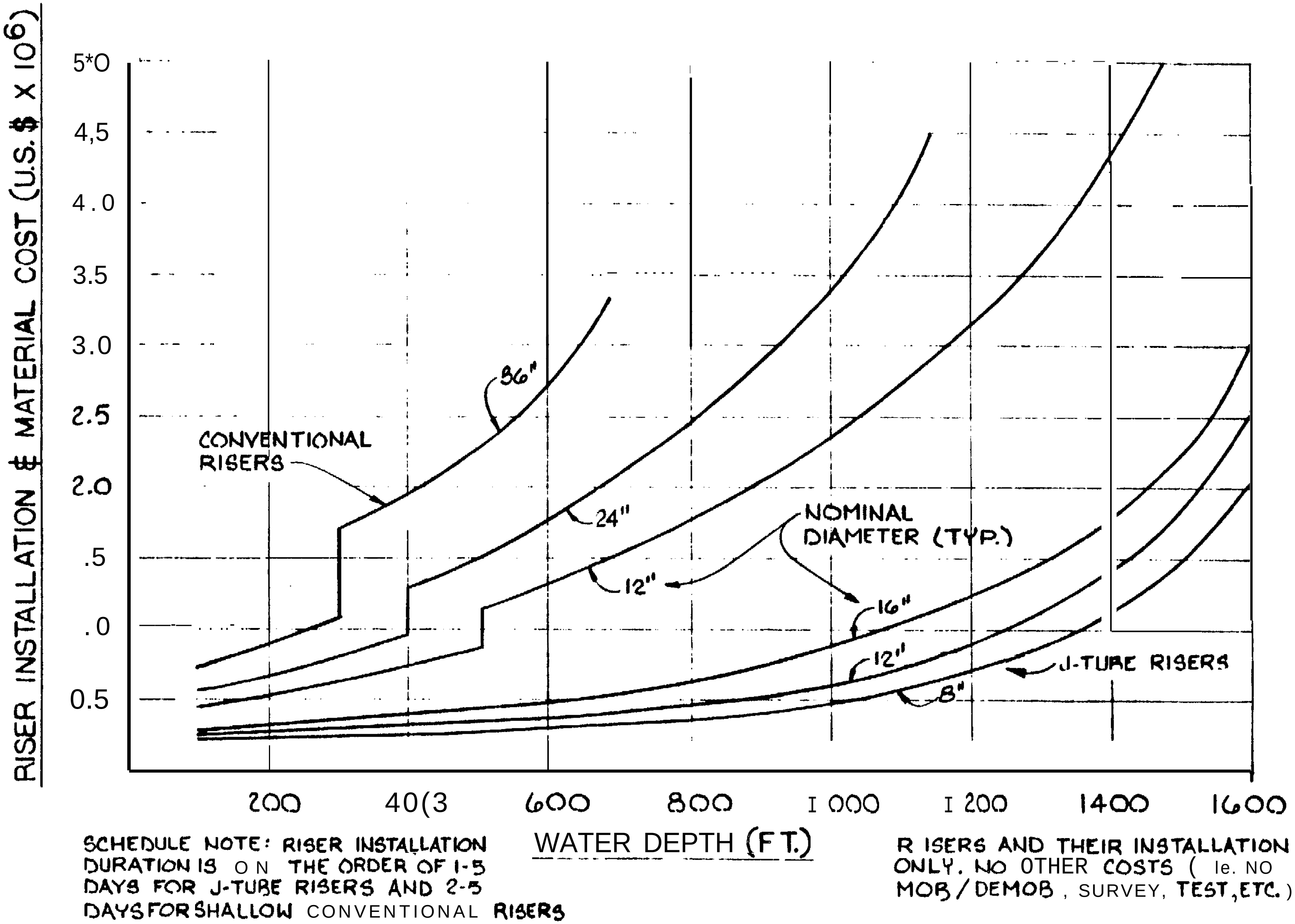
- PROJECT MANAGEMENT DESIGN, CERT. & CONSTR. INSURANCE
- PIPE COATINGS, BUCKLE ARRESTORS, ANODES, ETC.
- PRE & POST SURVEYS & BARGE ALIGNMENT
- HAUL, WELD, LAY, X- RAY & TEST
- NORMAL WEATHER DELAYS DURING WEATHER WINDOW

SCHEDULE

& MOS. DESIGN
6 MO 8. PIPE COAT & MOB
ALLOW : 10 DAYS PER 10 MILES OF LINE + 5 DAYS PER RISER OR TIE-IN + 1MO. FOR TEST, ETC.

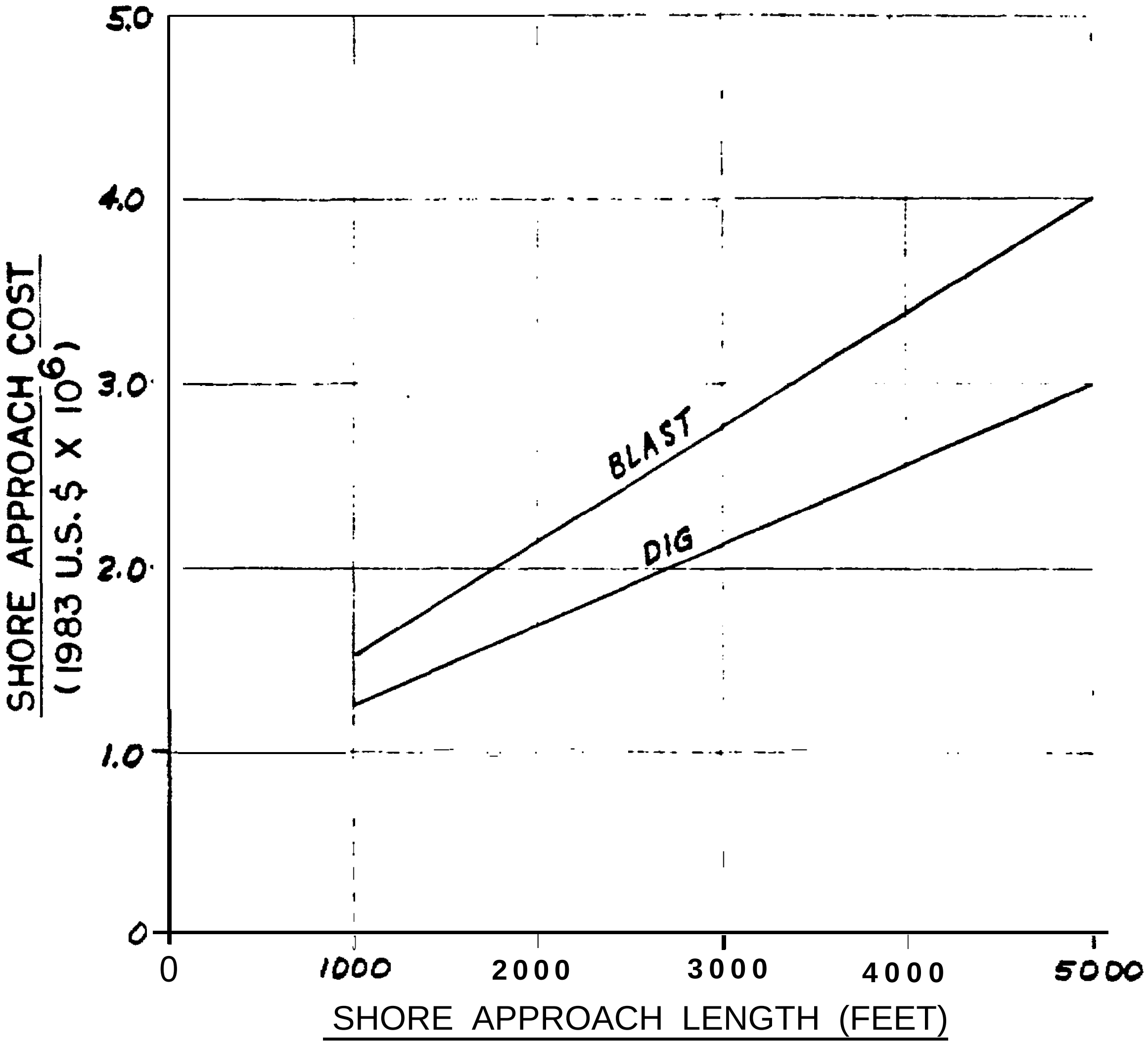
FIGURE 9-7

INFIELD PIPELINE COST & SCHEDULE



PIPELINE RISER COST & SCHEDULE

FIGURE 9-8



COST INCLUDES :

- PROJECT MANAGEMENT, DESIGN, CERTIFICATION & INSURANCE
- EXCAVATION & BACKFILL INCL. BEACH RESTORATION & ARMOR
- PULL SITE, ANCHOR + WINCH MOB, RENTAL & DEMOB.
- ONE SIZE FITS ALL LINE SIZES
- PIPE & INSTALLATION NOT INCLUDED (DO NOT SUBTRACT SHORE APPROACH LENGTH FROM DISTANCE TO MAINLINE LANDFALL. HOWEVER, DIFFERENTIAL LAYBARGE TIME TO SETUP & PUSH, ETC. IS INCLUDED)
- BASED UPON BARGE PUSH-PULL FROM SHORE METHOD

SCHEDULE (MOS.)

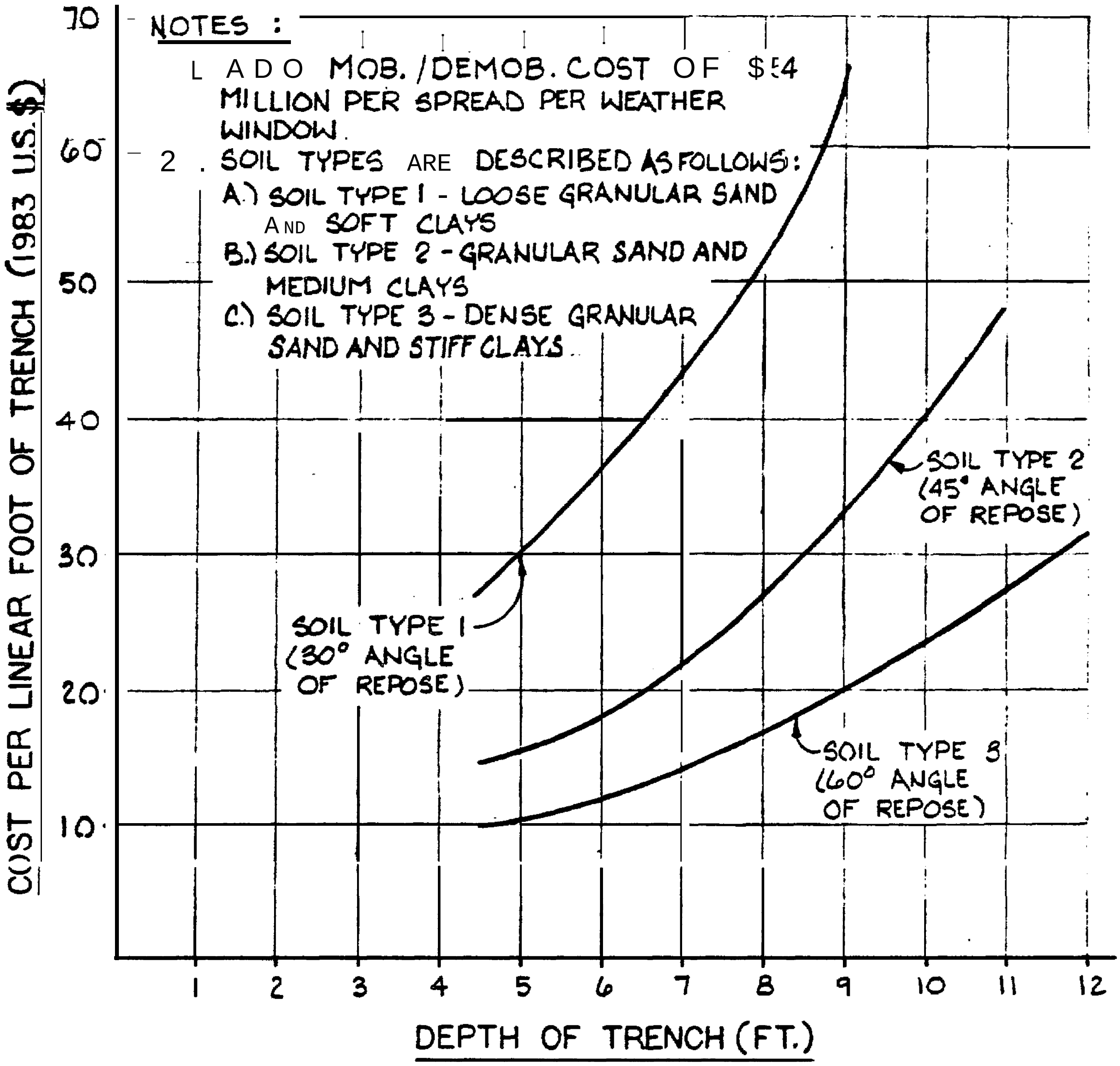
LENGTH	DIG	BLAST
1000'	17	22
2500'	18	24
5000'	19	27

INCLUDES 12 MOS. DESIGN

RESTORATION TAKES 3 MOS AFTER LINE IS TESTED.

PIPELINE SHORE APPROACH COST & SCHEDULE

FIGURE 9-9



SCHEDULE

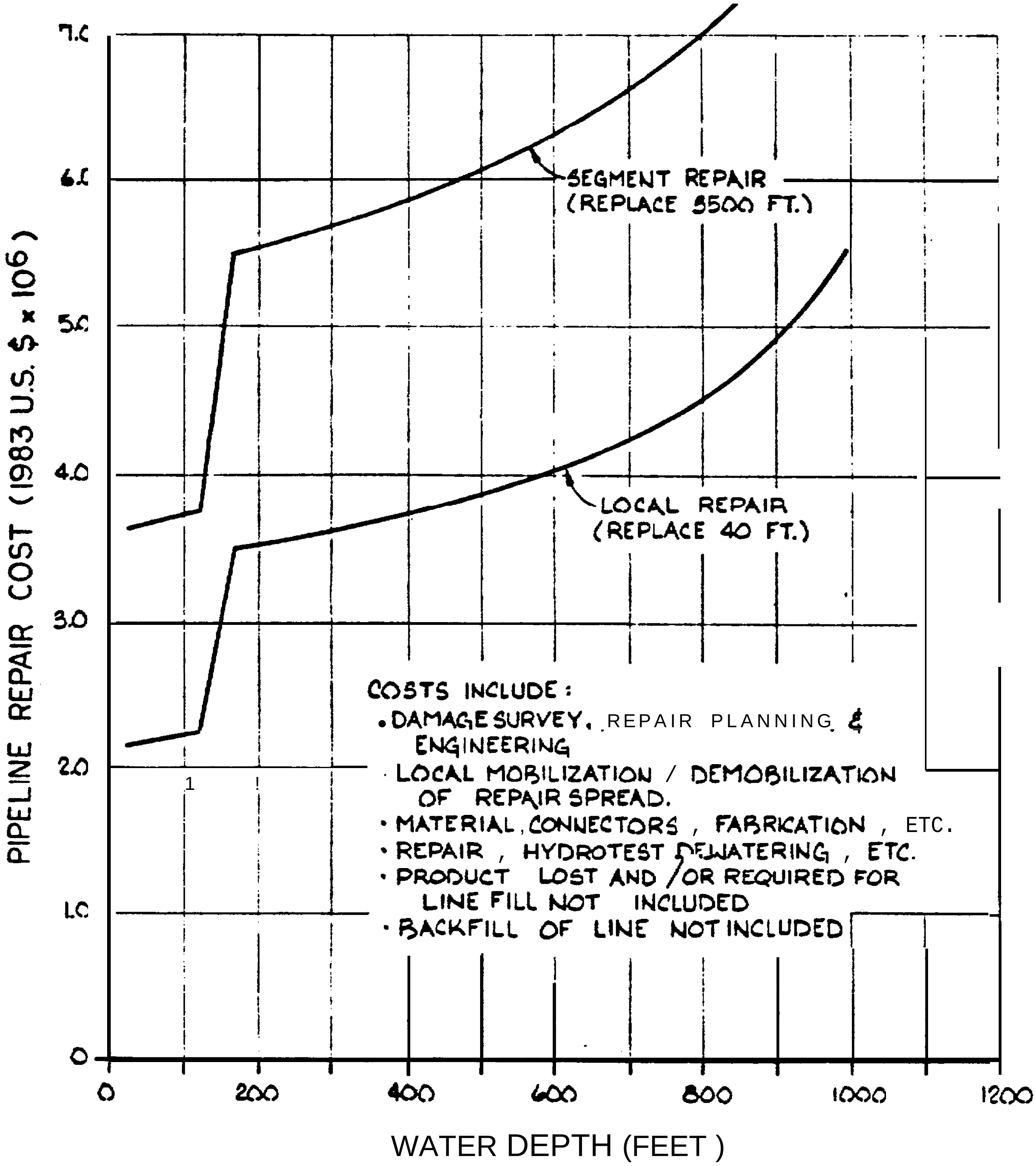
BURY MILES/SPREAD/WEATHER WINDOW

(240 DAY WEATHER WINDOW)

TRENCH DEPTH	SOIL TYPE 3	SOIL TYPE 2	SOIL TYPE 1
6'	420	240	140
9'	260	150	N.A.
12'	150	80	N.A.

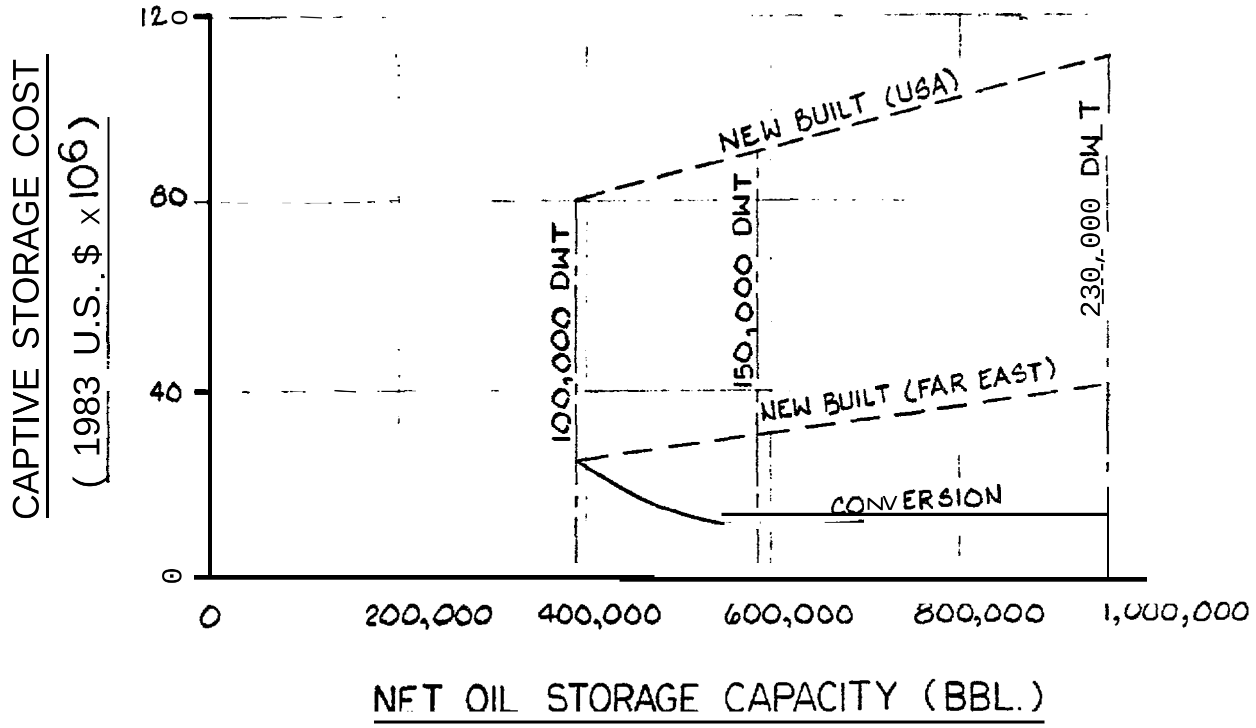
PIPELINE BURY COST & SCHEDULE

FIGURE 9-10



REPAIR SCHEDULE (DAYS)		
DEPTH	LOCAL	SEGMENT
250'	75	100
600'	80	105

FIGURE 9-11
PIPELINE REPAIR COST



SYSTEM INCLUDES : CONVERTED TANKER (SEGREGATED BALLAST)
SHUTTLE TANKER HAWSERS & HOSES (BOW TO BOW)

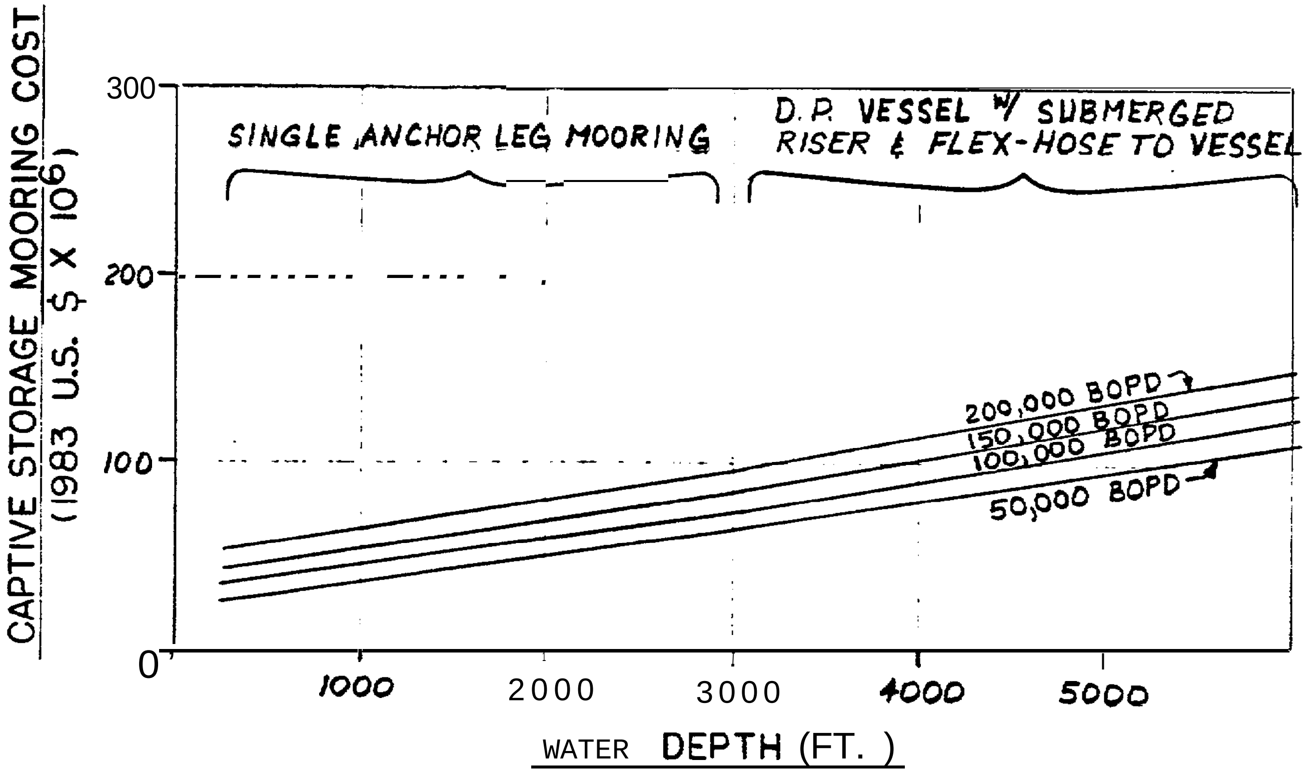
COSTS INCLUDE :

- PURCHASE TANKER @ SCRAP VALUE (EXCEPT 100,000 DWT)
- CONVERSION & CLASSING
- PROJECT MANAGEMENT, DESIGN, CERT. & CONST. INS.

NOTE: NEW BUILDING COSTS SHOWN FOR COMPARISON

SCHEDULE (MONTHS)	
ALL CAPACITIES	12 MOS.

FIGURE 9-12
CAPTIVE STORAGE TANKER
COST & SCHEDULE



SYSTEM INCLUDES: EXPORT PIPELINE FROM PLATFORM (2.5 MILES)
PILED BASE & CONNECTOR, RISER & SWIVEL OR
HOSES, AND YOKE. SHUTTLE TANKER HAWSERS &
HOSES (BOW TO BOW)

COST INCLUDE:
PROJECT MANAGEMENT, DESIGN, MODEL TESTS, CERTIFICATION
& CONST. INS., MATL., HARDWARE, FAB. & INSTALL.

SCHEDULE (MONTHS)	
1000' WD	36
3000 WD	54
6000 WD	66
INCLUDES	2-3 MOS. TO INSTALL

CAPTIVE TANKER MOORING COST

FIGURE 9-13

10.0 MANPOWER ASSUMPTIONS

10.1 Introduction

The OCS Petroleum Activities Direct Employment Model provides a suitable method for estimating total man-months of employment by task, for all units of work expected to be performed as the result for a specific OCS lease offering. The model is based upon a series of technical reports by Dames & Moore which provide information on employment factors by task for each geographic area of the Alaska OCS . These reports list task durations, crew sizes, number of shifts per day and rotation factors for the various activities involved in offshore development. The derivative OCS Model identifies twenty-two separate "units of work" that may be requi red for deepwater field development. Some of these activities are onshore, some are off sore; they are arranged according to their occurrence i n the exploration, development and production phases respectively.

The employment estimates in Section 10.2 rely heavily on the O.C. S. Model for the following specific activities, as outlined in Study Task 1D.

The employment estimates in Section 10.2 rely heavily on the O.C.S. Model for the following specific activities, as outlined in Study Task 1D.

A. Exploratory Well Drilling (Task 1 of the Model)
B. Platform Installation (Task 6of the Model)
C. Offshore Pipeline Construction (Task 10 of the Model)
D. Supply/Anchor/Tug Vessel Operations (Subtasks of Tasks 1, 6and 10of the Model)

The final activity listed in Study Task lD, "Concrete Platform Constriction," has been eliminated from consideration by the MMS.

Although environmental conditions vary for the three geographical areas under consideration, they are not sufficiently different to affect the employment estimates for performing the above activities in Alaskan OCS deepwater. The estimates shown in Table 10-1, therefore, are considered equally applicable for the Navarin and St. George Basins and the Gulf of Alaska. Each activity is on a per unit basis (i.e., one exploratory well, one drilling/production/ quarters platform, one subsea pipeline). Several platforms and pipelines may be required to develop commercial discoveries in the areas under consideration.

10.2 Manpower Requirements

The OCS Model allows one to develop not only the total number of persons required to carry out various activities, but also the total man-months necessary to complete these activities on a per unit basis. In Table 10-1, for example, a total of 152 persons are required for four months, organized into four crews of 38. These crews will work twelve hour shifts on an around-the-clock basis to complete one exploratory well. The Model shows that 608 man-months are required for each such well, but it must be carefully noted that this figure is not man months "on the job" (i.e., time for which wages are paid). The number of man-months per task per unit for which wages are paid in this case is 152. A new column has been added to Table 10-1 to show "Paid Man Months Per Task Per Unit."

The OCS Model allows one also to classify jobs by skill level and geographic origin. Table 10-1 does not attempt these classifications, but does show a range of wage rates deemed appropriate for the skills required for each task. In considering the suitability of native craftsmen for offshore work, there are many cases where little additional training would be required (e.g., electricians and pipefitters for hookup work). In these cases the

TABLE 10-1
EMPLOYMENT AND WAGE RATE ESTIMATES
TYPICAL SUB-ARCTIC DEEP WATER FIELD DEVELOPMENT
ALASKA OCS

		Task Crew Size	Shift Factor	Rotation Factor	No. of Crews/ Shift/Rotation/ Unit	Total Task Work Force Per Unit	Task Duration (Months)	Total Man-Months Per Task Per Unit	Paid Man-Months Per Task Per Unit	Range of Directly Hourly Wages
Task A	**Expl oratory**									
	Well Drilling	38	2.0	2.0	1.0	152	4	608	152	$20-$30
	-Supply & Anchor Boats	12	1.0	2.0	2.0	48	4	192	96	$15-$25
Task B	Platform & Production Equipment Installation	150	2.0	2.0	1.0	600	12	7,200	1,800	$10-$40
	-Tugboats	12	1.0	2.0	4.0	96	6	576	288	$15-$25
	-Supply & Anchor Boats	12	1.0	2.0	3.0	72	12	864	432	$15 - $25
Task C	Offshore Pipeline Construction	175	2.0	2.0	1.0	700	6	4,200	1,050	$10-$35
	-Tugboats	12	1.0	2.0	2.0	48	6	288	144	$15-$25
	-Supply & Anchor Boats	12	1.0	2.0	2.0	48	6	288	144	$15-$25
Task D	Supply/Anchor/Tug Vessel Operations	(Listed as Sub-tasks under Tasks A, B, and C)								

main emphasis would be placed upon acquainting onshore personnel with the unique safety and operational aspect of the offshore platform. In other cases (e.g., production operators) extensive training will be required.

The following parameters and factors have been used in Table 10.2-1.

Task Crew Size - The crew sizes used for the hypothetical "Baranof Basin Lease Offering (December 1985)" in Appendix A of the OCS Petroleum Activities Direct Employment Model are considered appropriate for use in these estimates.

Shift and Rotation Factors - The factors from "Baranof Basin" are used for these estimates.

No. of Crews/Shift/Rotation/Unit - The factors from "Baranof Basin" are again used for these estimates.

Task Duration (Months) - "Baranof Basin" values are used except in two instances, namely:

1) Tugboats for Platform and Producing Equipment Installation - Reduce duration from 12 months to 6 months.

2) Laying Offshore Pipe - Because of increased water depth and probable increased distance from shore, increase duration from 4.17 months to 6 months.

Man-Months Per Task Per Unit - This column from "Baranof Basin" has been split into two columns for clarity, i.e., "Total Man-Months Per Task Per Unit" and "Paid Man Months Per Task Per Unit".

Wage Rates - Wage rates are extrapolated from the state of Alaska publication entitled "Wage Rates for Selected Occupations, Anchorage, Fairbanks and Regional Areas, August 1982". The wage rate range is intended to include both skilled and semi-skilled occupations.

Use of the last two columns in Table 10-1 enables one to estimate total direct wages paid for a given activity on a "per unit" basis (e. g., one exploratory well).

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