BARGE-MOUNTED METHANOL PLANTS FOR DEVELOPMENT OF OFFSHORE AUSTRALIAN AND CANADIAN GAS FIELDS

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ABSTRACT

The use of a barge-mounted methanol plant (BMMP) as an alternative method of economic development of gas fields has been evaluated in this thesis. Recent increases in natural gas prices have improved the economics of producing small and marginal gas fields with the use of BMMPs.

There are two main advantages of using a BMMP as compared to a conventional production platform. First of all, the implementation time for a BMMP is much shorter which results in an earlier return on initial investment. Secondly, they can easily be relocated to another field upon the depletion of the gas in the original field. Thus the initial investment can be allocated between several fields.

The purpose of this thesis is to present a study of the various offshore Australian and Canadian gas fields. For Australian fields the BMMP was compared with conventional platform techniques using incremental economic analysis. This analysis was aided by using a computer program written by Mr. Konthi Kulachol and reprogrammed by Mr. Albert Chu. The results obtained from this economic program have helped in the decision-making process.

Australian gas fields studied in this thesis include the following: North Rankin, Angel, Goodwyn, Scott Reef, Tern, Penguin, Gorgon, Sunrise, Troubadour, Barracouta, Marlin, Snapper, Flounder, Turrum, Sole, Bream, and Pelican.
The seventeen fields considered were divided into four geographic regions: Victoria, Tasmania, Western Australia, and the Northern Territory. The fields located in the Victoria and Tasmania regions were found not to be favorable for the BMMP primarily because of their shallow sea depths, short distances to shore, and proximity to marketing areas. The fields located in the Western Australia and Northern Territory regions yielded favorable results for the BMMP due primarily to their marginal status and remote locations.

Canadian prospects studied in this thesis include: the Beaufort Sea, the Arctic Islands, the East Coast and the West Coast. Special problems are encountered in most of Canada due to the harsh environmental conditions. These problems make it difficult to transport the natural gas from the remote areas economically.

Onshore, the BMMP looks very promising in the Beaufort Sea and the Arctic Isles areas. A crude oil-in-methanol dispersion pipeline has been proposed from the Beaufort Sea to southern Alberta. This pipeline will transport both oil and methanol in a single carrier as opposed to two separate carriers. The economics of this proposal indicate that the O/M dispersion system will be approximately 60% of the cost of oil plus gas pipelines or $22 billion less expensive.

The Arctic Isles contain enough gas to justify the implementation of both LNG and BMMP schemes. The new barge-mounted mineral processing plant on Little Cornwallis Island demonstrates that BMMPs can be transported and operated in the Arctic. Tankers similar to those used in the Arctic Pilot Project can be
used to transport MeOH to markets in Eastern Canada and/or Europe.

East Coast Canadian gas fields studies in this thesis include the following: Thebaud, Venture, Gudrid, Bjarni, Snorri, Hopedale, and Hibernia.

The seven fields considered were divided into three geographic regions: Scotian Shelf, Labrador Shelf, and the Hibernia area. The fields located in the Labrador area were found to be unfavorable because of their flow rates and hazardous location near the Arctic area. The fields located in the Scotian Shelf and Hibernia regions yielded favorable results for the future application of BMMP.

The Canadian West Coast also has promising characteristics for the implementation of the BMMP concept. It is difficult to determine this feasibility due to the lack of data and current moratorium on offshore British Columbia drilling. In the future, if smaller gas fields are discovered, it appears that the BMMP would be a highly practical alternative.
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I. INTRODUCTION

The development of the BMMP is a recent concept which was first considered at Stanford University in 1973. Indirectly, the motivation behind this was the quadrupling of oil prices in 1974 by OPEC countries. This increase of price made it possible to consider development of small and marginal gas fields heretofore uneconomical.

The continent of Australia has numerous offshore gas fields where application of the BMMP system appears to be feasible. The use of conventional production platforms offshore of northwestern Australia would be a difficult process because of deepwater problems, variability of sea bottom, and shifting tidal currents. Environmental factors such as these make the BMMP attractive in this kind of location. The Exmouth subsea plateau area is located in deep water ranging from 335 to 1920 meters which is also advantageous for the use BMMP.

Applications in Canada are limited because of environmental constraints. There are four areas in which the BMMP appears to have future application potential. These four areas are the Scotian Shelf region offshore Nova Scotia, the West Coast area offshore British Columbia, the Beaufort Sea, and the Arctic Islands.

Methanol has several major potential uses such as a power plant fuel, a gasoline additive, and a nutrient for single cell protein. It can be stored and transmitted at atmospheric pressure. Methanol also burns with a non-smoky flame and yields only a small amount of pollutants. These qualities make it very
desirable for use as a fuel for automobiles and power generating plants. With increased methanol production at competitive prices, markets for the fuel will increase as its advantages are recognized.

The deregulation of U.S. natural gas prices in the near future is expected to result in gas price increases. This may help accelerate the development of remote, small and marginal gas fields using the BMMP.
II. LITERATURE SURVEY

Although the BMMP is a relatively new concept, there are many publications relating to its potential applications. In this literature survey the author has gathered material relating to most facets involved in developing the BMMP.

The most comprehensive study to date was prepared by Kulachol [47] who described the various factors involved in the development of the BMMP. He concluded that on the basis of 1980 cost estimates, the future use of BMMPs would be both feasible and profitable. With gas price increases that seem to be inevitable in the future, the use of BMMPs should become more widespread as the economics for developing small fields improve.

Swedyards Development Corporation [9,55] has designed and is capable of building BMMPs for development of small and marginal gas fields. Their reports contain a wide range of information including: the market potential for methanol, the design of the BMMP, the gas-to-methanol process, and worldwide possibilities for the use of the BMMP.

For organizational purposes in this thesis, the continent of Australia was divided into three regions. Recently, the most active exploration regions have been Western Australia and the Northern Territory which were discussed in articles in the Oil and Gas Journal [4,5,6,7,26]. Thomas [75] and Weaver [80] have described the regional geology of the area and provided data useful for our study. Information on water depths, distances to shore, and leasing permits was provided in papers written by Kulachol [47], Smith [70], McGruth [52], and Newman [58].
complex ownership structure of the Northwest Shelf was described in detail by Young [84]. Auldridge [3] and Baker [8] discussed the design of a new 1500 km, 76 cm pipeline from Dampier to Wagerup to be used to transport gas to marketing facilities. The deepwater regions of the Exmouth plateau were described by Durkee [23].

Koroknay [46] described the Victoria and Tasmania areas which are presently dominated by conventional platforms characterized by highly deviated well patterns and subsea completions. Hayman [36] and Thornton [77] illustrated the Gippsland basin with detailed figures of gas fields and production platforms. White [81] presented a strong case for using a drillship in this area because of calm ocean conditions. Dry wellhead installations were recommended by Kulachol [47] in regions with these features.

Whyte [82] described South Australia and Queensland as relatively unexplored offshore areas. The Great Barrier Reef is situated offshore Queensland and presents a major environmental risk, as has been discussed by Sabitay [66]. The geology of the Great Barrier Reef and the resulting environmental problems were presented by Benbow [13].

The intrusion of politics and labor unions into industrial relations was discussed by Young [84]. Thompson [76] described the present situation in which contractors and investors are having their exploration and development activities controlled by the State and Federal governments. Increasing costs of hydrocarbon exploration and pipeline projects were discussed by McMinn.
The recent difficulty in raising funds through capital and equity markets was introduced by Keller [45]. Methanol may be produced from fossil fuels such as coal which was presented by Swedyards Development Corporation [55]. Fettweis [29] illustrated the various types of coal deposits in Australia for present and future considerations.

For this thesis Canada was divided into four regions based on geographical location. The future potential of the Beaufort Sea has been discussed in articles in the Oil and Gas Journal [10,11,14,25]. Harrison [35] described Beaufort Sea production as being feasible by the mid-1980s.

An excellent summary of the exploration prospects and future petroleum potential of the Canadian Arctic Islands was written by Rayer [65]. Summaries of wildcat wells drilled in the Arctic were presented in the Oil and Gas Journal [30,31].

The Polar Gas Project which involves pipelining gas from Canada's Arctic Frontiers was discussed by Kaustinen [44] and Long [49]. Innovations in Arctic pipelining for underwater crossings were detailed in Ocean Industry [40] and the Oil and Gas Journal [59].

The Arctic Pilot Project is based on the conversion of natural gas to LNG which can be transported by ice-breaking tankers [16]. The project design and operations were described in detail by the Petro-Canada Journal [1] and the economics were summarized in The Oil and Gas Journal [2].

The prospects off Atlantic Canada were discussed by Oilweek [74]. The potential of the huge Hibernia field has been described in the Oil and Gas Journal [33,34,43,72]. Designing a
year-round production system for offshore Labrador was discussed in Ocean Industry [22].

Prospects off British Columbia and descriptions of the geology and future potential were discussed in articles in the Oil and Gas Journal [62,64,68]. Soul diced [65] described the two major sedimentary basins off the Western Canada Continental Shelf.

Various political problems between the Federal and Provin-
cial governments were discussed by Edmiston [24]. The National Energy Plan in Canada and its effect on the economy was discussed in the Oil and Gas Journal [20,78] and by Maciej [50].
III. THE BARGE-MOUNTED METHANOL PLANT (BMMP)

In the following paragraphs, the author will describe the basic fundamentals underlying the design of the BMMP. The present requirements for the BMMP shall also be described as viewed by prospective BMMP manufacturers. The purpose and advantages of the BMMP shall be described and complemented by a discussion of the market for methanol in today’s society.

A. Purpose of the BMMP

1) Development of Small Gas Fields
2) Development of Economically Marginal Gas Fields
3) Development of Deep Water Gas Fields
4) Elimination of Gas Flaring

The development of the BMMP is a relatively new concept and was first considered in 1973. The motivation behind this idea was mainly the quadrupling of oil prices in 1974 by OPEC. The increase in price made it possible to consider development of small and marginal offshore gas fields. The use of BMMPs in areas where gas is flared may also be advantageous in saving valuable energy. This concept may also prove to be useful in the future for this development of fields in deep water areas using subsea completion techniques [56].

According to Litton Energy Systems, approximately 20 billion cubic feet of gas are being wasted daily through flares. They also estimate that at least 150 BMMPs will be required to utilize the gas currently being flared and possibly another 150 to process the known natural gas reserves located in areas where markets do not and will not soon exist. Using 1979 data, 100 barges could supply the energy equivalent of 15.2 per cent of the United
States oil imports, or 6.9 per cent of total oil consumption.

B. Advantages of the BMMP

1) Implementation time for a BMMP is much shorter than for a production platform (Fig. 3-1). This time differential is at least nine months and probably much more than this.

2) BMMPs will be more suitable for deep water locations and remote fields [47].

3) BMMPs can be relocated to another field very easily after depletion of the first.

Economic analysis of the BMMP versus the conventional production platform for small and marginal fields indicates that the former is advantageous. With future oil prices increasing, the demand for producing these small fields will sharply increase, therefore resulting in a higher demand for facilities like the BMMP. The relocation aspect of the BMMP is a valuable asset in a particular area. In this case the initial investment can be allocated between the fields which will result in more favorable economic parameters for the decision making process [9].

C. Markets for Methanol

With increased methanol production at competitive prices, markets for the fuel will increase as its advantages are recognized. Methanol can be stored and transmitted at atmospheric pressure. It also burns with a smokeless flame and yields only a small amount of pollutants. These qualities make the use of methanol very desirable as a fuel for automobiles and power generating plants [48].
Figure 3-1: Project schedules for barge and platform systems.32
Presently, three billion gallons of methanol per year are being produced at inland plants. This is now being used almost entirely as a chemical feedstock. Methanol is an important raw material used in the chemical industry for producing formaldehyde, solvents, and various other chemicals. The manufacture of formaldehyde is approximately 50% of the total market with yearly increases of approximately 10% expected in the near future [39]. Methanol can now be used as a motor fuel by blending with gasoline up to 15% (by volume) [48]. In the future manufacture of engines using 100% methanol will be possible. Methanol and ethanol are interchangeable in turbines and in automobile engines with only minor carburetor changes. Today, U.S. automobile producers are catching up with their overseas competitors to mount full-scale research programs investigating the methanol alternative. It has been demonstrated that engines designed for methanol use are at least 30% more energy efficient than gasoline engines [48]. Methanol has been used for many years in racing cars because of its high performance [48].

Methanol can also be used in electric power generating plants and has been tested in gas turbine plants where it is considered to be an excellent fuel for peak hour shaving production. Clean-burning methanol has a particular benefit for utility companies in reducing overall emissions of the facility. This enables the user to meet the requirements established by the Environmental Protection Agency. In industrial centers methanol can be used for baseload power generation in order to reduce air pollution [39].
Applications of methanol in industry as fuel for diesel transport have also been successfully tested. This usually involves the development of a dual fuel system for use in diesel engines. With this type of system, approximately 85% of the diesel volume may be replaced by methanol to fuel trucks, buses, cranes, etc. [39].

Minor applications for methanol use include: synthetic proteins, anti-freeze, solvents, octane improver when used to make methyl tertiary butyl ether (MTBE), and as a chemical intermediate [9].

Natural gas price projections for the U.S., Canada, and Algeria are shown in Fig. 3-2. The price trends of both gasoline and methanol are shown in Fig. 3-3 [55].
**Figure 3-2: Natural gas price projections.**

1. ALGERIAN LNG PRICE PROJECTION BASED ON ANTICIPATED PARITY TO CRUDE OIL PRICES - (85 %) 1980-85

2. CANADIAN NG PRICES BASED ON CHEM SYSTEMS PROJECTION OF 75 % PARITY TO CANADIAN CRUDE OIL

3. US DOMESTIC NG PRICE PROJECTION - CHEM SYSTEMS
Figure 3-3: Price Trends for Both Gasoline and Methanol.
IV. DESIGN OF THE BARGE-MOUNTED METHANOL PLANT

The barge-mounted methanol plant consists of three modules:
1) Process Module
2) Storage Module
3) Living Accomodations

A. Process Module

Desulphurization of Natural Gas (Fig. 4-1)

The natural gas may contain various sulphur compounds which have to be removed before entering the primary reformer in order not to poison the reforming catalyst.

The desulphurization operation consists of mixing the natural gas with small amounts of recycled synthetic gas before being heated in a heat exchanger. The hot mixture is then passed through a hydrogenation vessel where the organic sulphur compounds in the hydrocarbon mixture are hydrogenated to hydrogen sulfide over a Ni-Mo catalyst. The next step is the absorption of the hydrogen sulfide in ZnO absorbers. In this process the natural gas is reduced to a sulphur content of about 0.1 ppm sulphur by weight.

Reforming (Figs. 4-2,3,4,5)

In this process the reactions take place in a gas-fired reformer. The hydrocarbon feed coming from the desulphurization unit is mixed with steam. This reaction mixture is preheated in the reformed flue gas section and then decomposed primarily into hydrogen, carbon monoxide and carbon dioxide over a Ni catalyst.

Methanol Synthesis Loop (Figs. 4-1,2)

The synthesis gas is next compressed and heated in the heat
exchanger before entering the methanol converters. The methanol synthesis section consists of two separate radial Topsoe-type converters where carbon monoxide, hydrogen, and carbon dioxide are converted into methanol by the following reactions:

\[
\begin{align*}
\text{CO} + 2\text{H}_2 & \rightarrow \text{CH}_3\text{OH} + Q \text{ (Kcal)} \\
\text{CO} + 3\text{H}_2 & \rightarrow \text{CH}_3\text{OH} + \text{H}_2\text{O} + Q \text{ (Kcal)}
\end{align*}
\]  

(4.1), (4.2)

There are also a few side reactions taking place with the formation of small amounts of dimethyl ether, methane, higher alcohols, aldehydes, and ketones.

The effluent gas from the second converter is first cooled in the heat exchanger and then further cooled in a water cooler, where raw methanol is condensed. The gas-liquid mixture passes to a separator, where the liquid product is separated. The non-stoichiometric gas from this process is then used as a reformer fuel. The remaining part of the gas is sent to the recirculator, where it is mixed with the make-up gas, recompressed and again sent through the converters.

**Methanol Distillation System** (Figs. 4-3,4,5)

In the distillation system the raw methanol is separated into water and methanol components by means of rectification. Acetone, aldehydes, and higher alcohols in the raw methanol are not specifically separated because of their positive heating value contribution to the fuel grade methanol. The finished product is cooled and then pumped to a storage tank maintained at atmospheric pressure.

**B. Storage Module** (Figs. 4-2,3,4)

The storage capacity is between 30,000 and 40,000 metric
tonnes of methanol which is approximately 10-12 days of production. The process plant can handle 3000 metric tonnes per day, which is based on approximately 95 MMSCF/D of gas.

The storage module is usually divided into nine different tanks, consisting of six fuel grade methanol tanks, two methanol shift tanks, and one raw methanol storage tank.

C. Living Accomodations (Figs. 4-2,3)

Adequate space for approximately 80 people is located at the fore end of the barge at a maximum distance from the process area. The living facilities consist of four decks which are fire-insulated and fully air-conditioned.

D. Mooring System (Fig. 4-6)

A single point mooring system which allows the barge to rotate freely around the pivot will be used for maximum flexibility. This mooring system will allow the barge to move to a position of least resistance with respect to waves, currents, and wind.

The mooring buoy will also act as a gas flow mechanism which will enable gas to be transferred to the barge. Presently, there is a limitation of approximately 300 m movement for the buoy system depending on sea conditions.
Figure 4-1: Process System for Barge-Mounted Methanol Plant.
Figure 4-3: Barge-Mounted Methanol Plant (Side View)

Figure 4-4: Barge-Mounted Methanol Plant (Upper Deck)
Figure 4-5: Barge-Mounted Methanol Plant (Aft View).
Figure 4-6: Mooring System.\textsuperscript{9}
V. APPLICATIONS IN AUSTRALIA

Australia has numerous offshore gas fields with total proven reserves of approximately 31 Tcf (Fig. 5-1) [42]. Areas of recent exploration and development are shown on Fig. 5-2 [6]. The northwestern area of Australia has many gas fields located primarily on the NW Shelf which has reserves of about 13 Tcf. The gas fields considered for development in Western Australia are the North Rankin, Angel, Goodwyn, Scott Reef, Tern, Penguin, and Gorgon fields. In the same geographic area there also exists the Exmouth subsea plateau region in deeper water (335 to 1920 m) which is regarded as the "last frontier" by many wildcatters. In such regions drilling must be done from dynamically-positioned ships and the cost is about $10 million per well. Large reservoirs of at least 2.81 Bcf must be discovered in order to justify production platforms [26].

The Bass Strait region is also a prospective area for development of gas fields by BMMPs. This area is currently producing 45 per cent of Australia's indigenous gas (315 MMcfd). In this area there are only a few small fields producing because of the high waste involved. The Snapper gas field has recently been put on stream at a cost exceeding $200 million [36]. The gas fields considered for development in Victoria are Barracouta, Marlin, Snapper, Flounder, Turrum, Sole, and Bream fields. Fields such as these may provide opportunities for use of the BMMP system.

Gas fields considered for development in the Northern Territory are the Sunrise and Troubadour fields while the Pelican gas field is the only prospect in Tasmania.
Figure 5-1: Prospective Oil and Gas Fields in Australia.42
Figure 5-2: Exploration Areas for Oil and Gas.\textsuperscript{6}
The lack of readily available data has prevented the author from further study on additional fields.

A. Western Australia and the Northern Territory

In the last year over 80 exploration companies have bid for most of the offshore leases in Western Australia [58]. Figure 5-3 illustrates the state's major sedimentary basins and petroleum discoveries [80].

The North West Shelf is a northeast-trending chain of basins and arches which include the Exmouth plateau and Rankin platform at the southwest end, and extends over 1500 km northeast to the Bonaparte Gulf Basin. It is this region which is receiving the most attention in present leasing and drilling operations and in which Australia's major reserves have been located [80].

An estimate of 15 trillion cu ft of recoverable gas has been made in the Rankin platform area, a northeast-trending series of fault-controlled structures. The Dongara gas field should produce in excess of 400 billion cu ft of gas which can be delivered directly to the Perth area [52].

The Exmouth Plateau is to be explored over a six-year period. An exploration expenditure of approximately US$300 million by four major oil companies is projected [80].

Hydrocarbon occurrences in various locations throughout Western and Northern Australia with respect to geologic age are summarized in Fig. 5-4 [80]. A geological map (Fig. 5-5) of the Australian Northwest Shelf helps illustrate structural features from gravity, magnetic and seismic surveys [75].
Figure 5-3: Major sedimentary basins in Western Australia.80
Figure 5-4: Hydrocarbon occurrences in Western Australia basins.
Figure 5-5: Geological map of Australian Northwest Shelf.
Figure 5-6 shows the Woodside Group's portion of the Australian Northwest Shelf where more than 60 exploratory wells have been drilled [75]. The first major gas discovery occurred in 1971 at Cott Reef which is 435 km offshore in the northern area of the permits. Gas was also found at North Rankin, Goodwyn, and Angel in 1972 which is shown in Figure 5-7 [52].

The Rankin Trend fields -- North Rankin, Goodwyn, and Angel -- are grouped about 130 km offshore in depths ranging from 130 m at North Rankin and Goodwyn to 90 m at Angel [52].

The high risks and costs of wildcatting on the deepwater Exmouth Plateau pose major challenges for the industry. This area is considered by most Australian wildcatters as perhaps the "last frontier" for possible giant discoveries. The basin is divided into five nearly equal license areas assigned to privately-owned, Australian-foreign partnerships and consortia (Fig. 5-8) [26].

The ownership structure of the North West Shelf Project, an unincorporated joint venture in which the Australian ownership of the project is about 48%, is shown in Fig. 5-9 [84].

In order to give a better physical understanding of the regional geology, Figs. 5-10,11,12 are presented. The Dampier sub-basin (Fig. 5-10) contains more than 6,100 m of Mesozoic and Tertiary sediments, whereas the geology in the Browse basin (Fig. 5-11) is not well-known because of limited well control. Offshore Bonaparte Gulf basin (Fig. 5-12) is a seaward extension of the onshore basin highlighted by horst and graben features overlain by late Mesozoic to Tertiary sediments [75].
Figure 5-6: Sixty exploratory tests drilled on the Australian Northwest Shelf.75
Figure 5-7: The Northwest Shelf.52

Figure 5-8: The Exmouth plateau search.26

Figure 5-9: The Northwest Shelf ownership structure.84
Figure 5-10: The Dampier sub-basin.

Figure 5-11: The Browse basin.
In mid-1980, the Western Australia SEC decided to build a $540-million, 1500 km pipeline to move gas from Dampier to Wagerup, about 110 km south of Perth (Fig. 5-13) [67]. This pipeline is expected to be completed in 1984 with a capacity of approximately 300 MMcf/d of treated gas from the North Rankin field [4,8].

Recent offshore Western Australia discoveries, including Gorgon, Penguin, Scott Reef, and Tern fields, will possibly have positive effects on the future use of the BMMP in this area [5,6].

The use of the BMMP in Western and Northern Australia requires the consideration of methanol transportation distances because of the remote field locations (Fig. 4-14). In the economic analysis it is necessary to include the transportation costs from the well location to the marketing facilities for the BMMP as compared with constructing onshore pipelines for the conventional method [75].
Figure 5-13: Route of proposed 1500 Km, 76 cm gas pipeline from Dampier to Perth.
Figure 5-12: The Bonaparte Gulf basin.

Figure 5-14: Orientation of gas fields from marketing facilities.
B. Victoria and Tasmania

Until recently, development of hydrocarbon reserves in the Bass Strait has been restricted to conventional platform techniques [46]. Figure 5-15 illustrates developments installed in association with the Bass Strait hydrocarbon reserves [36]. The installation of a platform is beneficial for the initial development of an area but becomes uneconomic for marginal fields. Two industry firsts in Australia were achieved in 1979 by the ESSO-BHP partnership in Bass Strait. The use of high angle wells from platforms and subsea completions was initiated to recover reserves in outlying reservoirs, beyond the reach of conventional techniques. Figures 5-16,17 illustrate these two innovative techniques [46].

Gas fields studied within the Gippsland Basin include Marlin, Barracouta, Snapper, Flounder, Turrum, Bream, and Sole (Fig. 5-18) [77]. Production platforms within the Gippsland Basin will have increased from seven to eleven by 1984 (Fig. 5-19) [36].

The Pelican gas field, located in Tasmanian waters, is a recent development [70]. Data used in the computer program to determine the economic feasibility of the BMMP in this area is to be found in papers by Smith and Kulachol [47,70].

The sea depth in this region was found to vary from 45 m (Barracouta) to 130 m (Sole) while the distance to shore varied from 25 km (Barracouta) to 100 km (Flounder). Flow rates based on reserves and initial flow rate capacities ranged from 25 (Bream, Sole, and Turrum) up to 165 MMCFD (Marlin). The average formation depth was reported to be approximately 2500 m [70].
The Victoria and Tasmania gas fields are located in relatively calm waters (Zone 1) [46] which makes them prime candidates for drilling with a semi-submersible rig or a drillship [81]. Rig, trench, and laying vessel downtime is minimal due to calm ocean conditions. A dry wellhead installation accompanies with single completion techniques will be primarily used in this area [47].
Figure 5-15: The Gippsland area.

Figure 5-16: Cobia-2 subsea completion.

Figure 5-17: Mackerel deviated well pattern.
Figure 5-18: Gippsland production platforms.

Figure 5-19: Locality map, oil and gas fields, Gippsland Basin.
C. South Australia and Queensland Outlook

During the period 1966-70, three seismic surveys totalling approximately 23,000 km were shot in offshore South Australia. The geophysical results prompted the planning of six well drilling programs to commence in early 1972. Two dry wells, Platypus-1 and Echidna-1 were drilled in 1972 in SA-6 and SA-7 (Fig. 5-20), with Platypus-1 providing some geological encouragement. Several more prospects were located in SA-6 and SA-7 according to the 1973 and 1974 seismic surveys, but these were not economically justifiable.

In 1975, the drilling of Potoroo-1 in SA-5 severely downgraded the prospectivity of that permit, but provided vital geological information relevant to permits SA-10 and SA-11. A detailed seismic survey in the latter two permits was shot in 1976. Prior to 1976, the main incentive for exploration in deepwaters was due to the presence of a very large anticlinal trend in the central part of SA-10. Interpretation of the 1976 seismic survey revealed this trend to be non-prospective, and as a result SA-10 and SA-11 were relinquished in April 1977. This ended a program in which three wells were drilled and about 25,000 km of seismic data recorded for a total cost of $16 million [82].

Since 1965, geophysical exploration and drilling in the offshore area of Queensland has been extremely limited (Fig. 5-21). The formation of a Royal Commission to study possible adverse effects on the Great Barrier Reef due to oil exploration has hindered progress on seismic programs. The Commission concluded that risks of hydrocarbon spills were small enough and
hazards from such spills not detrimental enough (except for dispersants and sinking agents) that drilling in selected areas should take place after improving safety precautions [66].

The Great Barrier Reef National Park Act came into effect during 1975. There are provisions in this act allowing or forbidding the recovery of minerals in certain zones of the Great Barrier Reef region. To date neither the zones nor the regulations governing exploration under the Act have been proclaimed [66].

The Great Barrier Reef Region covers approximately 207,000 sq km of Queensland continental shelf. The Reef varies geologically from Late Tertiary to Recent age with reefal growth mainly over platform areas of shelf sediments or basement rocks [13].

Underneath the Reef area exists seven basins which are either wholly or in part offshore. Listed from north to south (Fig. 5-22), these basins are the Peninsula Trough, Laura Basin, Halifax Basin, Hillsborough Basin, Styx Basin, Capricorn Basin, and the Maryborough Basin [66].

To date there has been only one offshore well drilled in this area and there were no live shows of oil and gas present. The petroleum potential of this region will remain speculative until further drilling is carried out to assess the stratigraphic section [13].
Northeastern Australia and the Gulf of Papua.

Figure 5-20: Permit boundaries for offshore South Australia.86

Figure 5-21: Northeastern Australia and the Gulf of Papua.66
Figure 5-22: Major features of the Great Barrier Reef Region.
D. Australia’s Coal Resources

Figure 5-23 shows the location of the known hard and brown coal resources in Australia. The main deposits of hard coal are near Sydney in New South Wales, and in Queensland further to the north. Significant brown coal deposits are located near Melbourne in the State of Victoria [29].

Methanol may be produced from fossil fuels such as coal or from renewable resources such as wood. Various processes can be used to synthesize methanol from feedstocks such as coal, wood, char and natural gas using various combinations of catalysts, temperature and pressure. Conversion efficiency may be 50-60% due to process heat losses, but production costs can be quite reasonable when compared with ethanol and competitive with petroleum, particularly in large scale plants.

This general overview of Australia’s coal resources should help the reader in understanding that several alternatives are available for methanol manufacture in the future.
2 Bowen hard coal basin, Queensland
3 Clarence-Moreton hard coal basin, Queensland and New South Wales
4 Galilee hard coal basin, Queensland
5 Latrobe Valley brown coal basin and associated coalfields, Victoria
6 Smaller coal occurrences

Figure 5-23: Location of coal occurrences in Australia
E. Political Environment

The unique Australian system of controlling industrial relations matters was created in the early 1900s because of national strikes in the 1850s and during the formation of the Commonwealth of Australia. The division of powers between the Commonwealth and State Governments causes inconsistencies which have increased the intrusion of politics into industrial relations problems [34].

The expansion of onshore exploration and production of the hydrocarbons industry into offshore areas has resulted in more unions becoming involved in the industry. This results in complications between land-based and maritime unions in approaches to construction and production work. It will require a lot of effort by employers and their organizations to overcome the industrial relations difficulties that will arise at interfaces between them and other well-established industries [84].

Increased petroleum exploration and development activities offshore Western Australia will continue to attract the focus of many companies, contractors and investors who will find that their exploration and development activities are controlled by a mixture of State and Federal legislation. This mixed regime originates in international and constitutional law [76].

Increasing costs have created operating and investment problems for companies involved in the Australian hydrocarbon resource industry (Table 1, Fig. 5-24). In dollar terms, expenditure in this area has declined considerably which is an adverse trend given Australia's outlook for increasing reliance in imported crude oil in the 1980s [54].
Escalation in Australian offshore drilling rig workers' awards.

Table 1: Effect of water depth on Australian offshore drilling and development costs.

<table>
<thead>
<tr>
<th>Offshore Depth</th>
<th>Cost of Drilling One Exploration Well</th>
<th>Cost of Development One 7.950-15.900 kl a Field Day Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore — 30-45 m depth</td>
<td>$ million (1976) 2.2-3.0</td>
<td>170-250</td>
</tr>
<tr>
<td>Offshore — 140 m depth</td>
<td>2.2-3.0</td>
<td>350-620</td>
</tr>
<tr>
<td>Offshore — 60-920 m depth</td>
<td>9-12</td>
<td>350-9000</td>
</tr>
</tbody>
</table>

Figure 5-24: Operating costs for Australian offshore exploration drilling rigs.

Figure 5-25: Escalation in Australian offshore drilling rig workers' awards.
Costs in hydrocarbon exploration appear to have risen in excess of general inflation in the Australian economy. This situation may be attributed to rapidly rising wages (Fig. 5-25) and equipment costs. This has resulted in an escalation of capital costs for hydrocarbon development and pipeline projects (Table 2). Additional factors including design alterations, environmental considerations and labor disputes, can also increase costs significantly [54].

Increasing amounts of funds are required for exploration and development as a result of the rising cost trend. Recently, difficulty has been experienced in raising funds through capital and equity markets, as well as retained earnings. The most important factor in securing adequate funds is profitability, which is largely determined by State and Federal governments (Table 3) [45].

Costs are expected to continue to increase in hydrocarbon exploration and development, but at a lower rate than experienced in the mid-1970s. A strong future in the hydrocarbon sector is dependent on a favorable investment environment and higher profitability to offset the high risks in exploration and escalation in costs.
<table>
<thead>
<tr>
<th>Recently completed Projects</th>
<th>Capital Cost Estimates $ million</th>
<th>% Increase on Original Estimate</th>
<th>Estimates in 1966-67 Constant Dollars $ million</th>
<th>% Increase on Original Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW-South Australia</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Moomba — Sydney 86 cm, gas pipeline (estimates for current southern route)</td>
<td>145 August 1973</td>
<td></td>
<td>28</td>
<td>113</td>
</tr>
<tr>
<td>186 May 1974 (commencement of construction)</td>
<td>232 December 1976 (final cost)</td>
<td></td>
<td>60</td>
<td>101</td>
</tr>
<tr>
<td>Victoria</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Melbourne-Albury 30.5 cm, gas pipeline</td>
<td>12.7 November 1973 (original budget)</td>
<td></td>
<td>50</td>
<td>10.2</td>
</tr>
<tr>
<td>19.1 January 1975 (construction budget)</td>
<td>25.5 May 1977 (final cost)</td>
<td></td>
<td>101</td>
<td>10.6</td>
</tr>
<tr>
<td>Projects Planned or Being Constructed</td>
<td>South Australia</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Redcliff Petrochemical Complex</td>
<td>420 May 1974</td>
<td></td>
<td>43</td>
<td>332</td>
</tr>
<tr>
<td>600 October 1974</td>
<td></td>
<td></td>
<td>238</td>
<td>501</td>
</tr>
<tr>
<td>1,000 July 1975 (a)</td>
<td></td>
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<tr>
<td>Victoria</td>
<td></td>
<td></td>
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<tr>
<td>Tuna-Mackerel</td>
<td>100 October 1973</td>
<td></td>
<td>80</td>
<td>73</td>
</tr>
<tr>
<td>180 September 1977</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Western Australia</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>North West Shelf LNG export project</td>
<td>1975 Project (b)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production Capacity; 18.4 million cu m a day</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 Offshore platform and offshore pipeline</td>
<td>250-300</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNG Plant</td>
<td>400-500</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 or 8 LNG tankers</td>
<td>450-550</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>1100-1350</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>1977 project (c)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production capacity; 39.6 million cu m a day</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 Offshore platforms and offshore pipeline</td>
<td>900</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Domestic processing plant</td>
<td>100</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>LNG Liquefaction plant</td>
<td>700</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>7 to 12 LNG freighters</td>
<td>800-1300</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Total</td>
<td>2500-3000</td>
<td></td>
<td></td>
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</tr>
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</table>

(a) Excludes an estimate of $200 million to cover infrastructure needs.
(b) Values expressed in 1975 dollars.
(c) Values expressed in January 1977 dollars.
Sources: Charlton (1976a), Harrison (1977), McGrath (1977) Industry Sources.

Table 2: Capital Costs of Selected Hydrocarbon Projects in Australia.
<table>
<thead>
<tr>
<th>Year ended Dec 31</th>
<th>Gross Profit (a)</th>
<th>Net Profit (b)</th>
<th>Year ended Sept 30</th>
<th>Gross Profit (a)</th>
<th>Net Profit (b)</th>
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<td>3.8</td>
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</tr>
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<td>1971</td>
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<td>10.5</td>
<td>1971</td>
<td>11.7</td>
<td>11.1</td>
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<td>23.5</td>
<td>17.4</td>
<td>1973</td>
<td>11.0</td>
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<td>26.6</td>
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<td>1977</td>
<td></td>
<td></td>
<td>1977</td>
<td></td>
<td></td>
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<tr>
<td>Santos Ltd</td>
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<td>International</td>
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<tr>
<td>Year ended Dec 31</td>
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</tr>
<tr>
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<td>Australian Company</td>
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<td>Year ended Dec 31</td>
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<td></td>
<td>Profitability (e)</td>
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</tr>
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<td>GDP Deflator</td>
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<td>Year ended June 30</td>
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<tr>
<td>4.5</td>
<td>4.3</td>
<td>6.8</td>
<td>8.9</td>
<td>14.6</td>
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<td>11.3</td>
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<table>
<thead>
<tr>
<th>Year ended June 30</th>
<th>% increase on previous year</th>
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<tbody>
<tr>
<td>1970</td>
<td>4.5</td>
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<td>1977</td>
<td>11.3</td>
</tr>
</tbody>
</table>

**Table 3: Company profitability in the Australian hydrocarbon production sector.**

(a) Gross Profit: Profit before tax and interest.
(b) Net Profit: Profit after tax, interest but before extraordinary items.
(c) Year ended June 30.
(d) Six months ended December 31.
(e) Results of an extensive survey of medium to large companies operating in the oil sector of the Australian economy.

VI. APPLICATIONS IN CANADA

Encouragement to accelerate the onstream dates of major energy projects such as the Arctic Islands, the Beaufort Sea, and offshore Eastern Canada is needed to avoid serious energy shortages. The time estimated for Canada to fully replace present imports with Canadian sources from frontier lands or the Athabasca tar sands is approximately ten years.

Gains made in environmental standards both in the U.S. and Canada during days of energy surpluses will be reversed as the public mood changes with serious energy shortages. Therefore, it is necessary to plan major projects far in advance in order to maintain environmental stability and ensure a continuation of present lifestyles [19].

Canadian prospects studied in this thesis include: the Beaufort Sea, the Arctic Islands, the East Coast and the West Coast. Special problems are encountered in Canada due to the harsh environmental conditions. These problems make it difficult to transport the natural gas in remote areas at economical rates.

A. Beaufort Sea

Several requirements must be satisfied before Beaufort Sea oil and gas can be developed. First of all, it must be proven that a commercial size reservoir exists (400,000 bbl of oil recoverable per production platform). There must be a thorough understanding of the ice forces in respect to the construction and operation of the platform system. It must also be proven that an acceptable knowledge exists of the predicted performance of the tankers loading in the Beaufort Sea and moving through the
Northwest Passage. Finally, it must be shown that environmental risks can be accurately predicted for both production and transportation facilities [35].

Figure 6-1 is a map of the Canadian Arctic region with the Beaufort Sea area shown in the rectangle [25]. Figure 6-2 shows the results of seismic tests in the Beaufort Sea area [11].

Dome estimates there is as much as 32 billion bbl of recoverable oil in the Beaufort. They also claim that 400 million bbl of proven oil is the threshold reserve required to justify development of a field. Each field may cost $5-6 billion to develop [25].

The initial emphasis is on oil. Operators don't expect gas production from the Beaufort until 1992 at the earliest, with most associated gas reinjected prior to start-up of a gas delivery system [25].

By 2000 there could be two to five offshore producing gas fields connected by a subsea pipeline gathering system to an onshore pipeline. Gas also could be converted to LNG with six LNG carriers needed by 1992, each carrying 140,000 cu m of LNG, with a need for 16 LNG carriers by 2000 [25].

Dome estimates that Beaufort Sea expenditures (Fig. 6-3) could be as high as $44 billion in 1980 dollars through 1990. This would be the requirement for the discovery and development of 14 billion bbl of oil and the oil equivalent of gas in five oil fields and three gas fields. Of this total, exploration would account for only about 10 percent [11].
Figure 6-1: Canada's Arctic Area.25

Figure 6-2: Where seismic indicates Beaufort Sea structures.11
Figure 6-3: Beaufort Sea investment requirements.11
The $25 billion for oil development would include construction of barge-mounted drilling and production facilities that would be towed to location. This figure also includes the construction of icebreaker tankers. This development expenditure will develop production of about 200,000 b/d by 1986 and up to 1 million b/d by 1995 [11].

The $15 billion gas development outlay would include development drilling, barge-mounted production facilities, and a pipeline up the Mackenzie Valley [11].

Dome has had a high success rate on its Beaufort Sea acreage, most of which is in a transitional zone of seasonal pack ice between the permanent polar ice pack and landfast ice [11].

Beaufort operators view the technical challenges of exploring and developing the highly prospective area with confidence.

Most operators claim they encountered no significant technical problems in initial Beaufort efforts. Rigs are readily available, with at least six Arctic design rigs built for Beaufort type work.

Drilling in the Beaufort is enormously expensive. Wells requiring gravel islands cost $20-40 million. In waters less than 5 m deep and relatively close to shore, gravel islands probably will remain the practical choice. In deeper waters, exploratory drilling farther from shore involves astronomical costs to build gravel islands [25].

Sohio is working on designs for mobile rigs to withstand the severe Beaufort environment. But with the cost estimated at $20-40 million/rig, Sohio will not undertake construction until after
OCS Sale 71 scheduled for September 1982 [25].

Presently, the biggest problem with the Beaufort development is the five month drilling season, arbitrarily set from Nov. 1 - Mar. 31. Costs soar when operations are required to halt for seven months.

Because the governments involved have a big stake in Beaufort development, operators expect a decision by July 1982 rescinding the drilling season for leases but maintaining seasonal stipulations for individual well permits.

That would allow government to waive seasonal restrictions for development work, but retain them for exploratory wells, for the environmentalists [25].

Gulf is planning for a $674 million drilling system to begin operation in the summer of 1983 on 1.5 million acres of Gulf lands in the Canadian Beaufort [25].

Gulf has been active in the Beaufort since 1965 and is now beginning to develop its own drilling fleet. Gulf holds 2.7 million acres and has participated in 50 wells, including the Kopanoar, Tarsiut and Issungnak discoveries (Fig. 6-4) [25].

Dome released figures from the Dallas consulting firm of DeGolyer & MacNaughton which estimated Kopanoar reserves at 270 million to 1.8 billion bbl, and Koakuak’s reserves at 300 million to 2.0 billion bbl [11].

De Golyer & MacNaughton said regional data indicate several structures of similar size and geological setting as Kopanoar and Koakoak in the same area on Dome acreage, most of which have not been drilled [25].
Figure 6-4: Where Beaufort Sea leases are being tested.
Dome has also proposed additional appraisal drilling in 1982 at the Kopanoar and Koakoak locations. They are likely to remain the hot spots during 1982 and the key to proving commercial reserves for the structures most likely to be first on Dome's production schedule [25].

Dome is planning with its partners to build a $200 million artificial island at Koakoak in 1982. It should be possible to drill five or six delineation wells from the island, located in approximately 50 m of water, with a good supply of island-building material which can be dredged from the sea floor [25].

Dome officials describe the results at Kopanoar and Koakoak as "positive confirmation of major oil potential" [25].

A range of production options for various water depths is presently being used or under development. The main development effort is targeted for water depths of about 60 m [34].

For fixed platforms there are three main alternatives:

- artificial earthfill islands for the shallowest water;
- large gravity caissons in the middle depth range;
- the "Monocone" at the deep end of the scale [34].

Issunngnak artificial island (Fig. 6-5) in the Beaufort Sea is located 60 km off the coast in 20 m of water. Island stability is protected from wave action and ice shearing by wide sacrificial beaches around its perimeter and by numerous slope protection devices, including many meters of filter cloth and submarine netting [10].

Wave energy is dissipated on the long beaches. In the winter, numerous ice fields ground themselves out on the beaches, piling approximately 10 m high ridge around the island [10].
Figure 6-5: Issungnak artificial earth island.

Figure 6-6: Arctic production and loading atoll (APLA).
Islands are needed because water depths to 20 m are too shallow for drillships, and thick ice which is present eight months of each year prevents the use of jack-up rigs. The islands are cost effective and safe for year-round drilling and ultimate development [10].

An artificial island such as the Arctic Production and Loading Atoll (APLA, Fig. 6-6) designed by Dome could resist all ice forces. Following construction, process facilities and tanker loading facilities would be built on barges and towed by icebreakers. The facilities are protected in an enclosed production and loading basin from ice [35].

An alternative to gravel islands is to use a single massive concrete or steel caisson, prefabricated in the south, floated into position and ballasted down with pumped sand and gravel to counteract sliding forces. This technique also allows for the storage of oil.

This type of platform would be similar to a North Sea gravity platform without its substructure towers, and would probably be heavier than any previous platform used.

Preliminary indications suggest that such an approach could be feasible to 60 m water depth. The caisson also has the advantage of removability [34].

A caisson-supported artificial island, Tarsiut N-44, was completed in 23 m of water at a site 2 km east of the Tarsiut oil discovery. Tarsiut will function as a sophisticated testing ground for development of future drilling/production islands [34].
Four floatable concrete caissons weighing 5,300 tonnes each were built in Vancouver, towed to the island in July, 1981 and anchored atop the sand berm.

Tarsiut, with a life expectancy of about three years, will help develop engineering data required to build production islands and platforms with lifespans of 15-25 years. The concrete caissons which form the perimeter of Tarsiut can be refloated and moved to another location [25].

The production "Monocone" (Fig. 6-7) has three basic components: a doughnut shaped base, a wineglass mid-structure with sloping sides over its lower part, to fail ice upward, a slim vertical column in the main ice zone to minimize forces on it, and a jack-up deck [34].

To avoid a 1-in-100 year ice island, the deck and middle cone can be disconnected and floated out of the way. The subsea wellheads would remain snug in the base while the ice passes over [34].

Sea ice is the dominant environmental force in the Beaufort Sea. Sea ice throughout the Arctic Ocean is a complex variety of different forms, properties and behavior. Over the past decade, industry and government have conducted intensive studies of sea ice throughout the Beaufort Sea [35].

Recent investigation along the northwestern edge of the Arctic Islands and into the permanent polar ice pack reveals a spectrum of ice features, some similar in size and shape to those generated in the Beaufort, and others much greater in size and strength.
There are three orders of magnitude of force that might be designed against. These are:

1. Level ice combined with pressure ridges 35 m in depth (common)
2. Multi-year hummock fields 15 to 30 m thick and up to 5 km in diameter (rare)
3. Ice islands which calve from Ellesmere Island glaciers and which can be 60 m thick and 7 to 15 km in diameter (very rare) [35].

Fixed structures in the Beaufort Sea should be designed for possible collision with the largest, but rarest, of these features [35].

Ice in various forms and sizes usually is present for about nine months each year, but can be present year-round and move at any time under wind and current action. Ice movement can cause large lateral ice forces which require offshore platforms to be different from those in other areas. Beaufort platforms need large lateral shear strength to resist the ice (Fig. 6-8) [35].

Ice conditions get more severe in deeper water because the ice is more mobile, and thick multi-year and glacial ice features can be present. Therefore, earth islands in deeper waters need to be stronger by a substantial margin than those presently used.

Fig. 6-9 shows the relative profile size of a production island for 60 m water, exploration island for 20 m water and Ninian Central platform in 140 m water in the North Sea [35].

The company which has spent the most by far in ice research in the Arctic, mainly because it has the most to gain when Beaufort production commences, is Dome Petroleum. Its most intensive ice research has been performed through the use of its ice-
Figure 6-7: Production Monocone.\textsuperscript{34}

Figure 6-8: Relative shearing resistances and forces relative to possible ice forces in Beaufort.\textsuperscript{35}

Figure 6-9: Relative profile size of production island and Ninian Central platform.\textsuperscript{35}
breaker Kigoriak (Fig. 6-10) which is the most heavily instrumented ice-breaker in the world. Kigoriak is also the first ice-breaker to operate year-round in the Canadian Arctic for research purposes [12].

New equipment for dredging, moving and placement of earth material must be developed. This equipment must extend the working season in the ice, work at greater depths, work with larger quantities and longer hauls, and be able to place material more accurately than those capabilities available with present technology. Fig. 6-11 is a super dredge for production island construction which is expected to permit operations in water depths of 80-100 m [14].

For two decades, the fear of tanker spills has existed without improving the fundamental tanker design. With concern for the Arctic ecology, future tanker design will be revolutionized and hazards reduced considerably. Fig. 6-12 illustrates an ice-breaking super tanker which is a new concept designed by Dome Petroleum. Some of the features include:

1. ballast tanks located on the outside with the oil tanks in the protected center,
2. longitudinal beam strength three times that of a conventional tanker,
3. double and independent propulsion systems, and
4. inert gas systems to prevent explosive hydrocarbon gas buildup [35].

The official scenario for Canadian Beaufort Sea development as proposed by Dome Petroleum Ltd., Esso Resources Ltd., and Gulf Canada Resources Inc. calls for three phases.
Figure 6-10: Breaking Ice in the Beaufort Sea is Dome's Kigoriak.
Figure 6-11: Super dredge for production island construction.  

Figure 6-12: Dome's super ice-breaking tanker.
In the preproduction phase (1981-85), 30 offshore exploration and delineation wells would be drilled, approximately five from artificial islands and the remainder from conventional drillships and year-round drilling systems [25].

About five exploration islands would be built in water less than 30 m deep, each requiring 2-4 million cu m of dredged material. Approximately 15 development wells would be drilled.

One Arctic tanker would be built along with an offshore tanker terminal, or an oil pipeline would be under construction south in the Mackenzie Valley with an onshore terminal on the Arctic coast [25].

In the early production phase (1986-90) about 40 exploration and delineation wells would be drilled, approximately five from artificial islands and the remainder from conventional drillships and year-round drilling systems. About five exploration islands and four production islands would be built in less than 30 m of water [25].

One deepwater artificial island for development may be constructed using 30-50 million cu m of dredged material. From this island, about 160 production wells would be drilled with a combined production rate approaching 500,000 b/d [25].

In transportation, one deepwater Arctic production and loading atoll (APLA, see Fig. 6-6) would be built using 80-120 million cu m of dredged material and about 11 Arctic tankers could be in operation. Or two subsea pipelines would be built, joining a second offshore oil field with a shore terminal, and construction of an oil pipeline down the Mackenzie Valley would be completed [25].

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The long term production phase (1991-2000) calls for the drilling of approximately 80 exploration and delineation wells, about 10 from artificial islands and the rest from vessels. About 10 exploration islands using 2-4 million cu m of material each and eight production islands of 5-15 million cu m each would be built in shallow water [25].

One deepwater artificial island would be built, with the possibility of a second one scheduled for completion in 2001. Approximately 400 production wells would be drilled, and production would be increased to around 1125 million b/d [25].

Either two APLAs would be built and 15 more tankers (total of 26), or more subsea oil lines would be laid to link four more oil fields with shore-based storage tanks [25].
B. Arctic Islands

The Canadian Arctic, one of the world's largest archipelagos, extends 2,400 km west to east and 2,000 km south to north. This vast expanse of water and islands (1.7 MM sq km) is one of the most favorable prospective frontier exploration areas in Canada (Fig. 6-13) [18].

In the sparsely populated "high-Arctic", weather and communication stations have been established at scattered sites throughout the northern islands (Fig. 6-14). Resolute Bay on Cornwallis Island is the largest settlement which was established in 1947 as a joint U.S.-Canadian weathersite and later became an air force base. Inuit natives moved to Resolute in 1953 and it has been the center of high Arctic activity since then.

A second major supply base for exploration in the Arctic is Rea Point on Melville Island which was established in 1968 by Panarctic Oil as its base for communications and transportation with winter geophysical and drilling operations [18].

The islands are not continuously ice bound, and offshore areas are open for varying periods. The SE area usually is navigable by ship in summer, but the NW pack ice is seldom open (Fig. 6-15). The "NW passage", which bisects the archipelago, was the route of the icebreaker-tanker Manhattan from eastern North America to Alaska in 1969 [65].

Less than 10 percent of the land area is permanently ice covered. The arctic is a frozen desert averaging 5-13 cm of annual precipitation. The eastern, more mountainous islands are covered by ice caps and glaciers, whereas the western islands are bare of snow, and temperatures reach 20°C in summer.
Figure 5-13: The Arctic Archipelago.

Figure 6-14: Index map of Canada.
Figure 5-15: Ice-pack areas of Arctic Archipelago and "NW passage" of the tanker Manhattan.
The index maps (Fig. 6-16, 17) outline the basins in which more than 140 wells have been drilled for hydrocarbons since the first exploratory well, Winter Harbour, was drilled in 1961 [14].

Permits for exploration were first issued in 1960, and Panarctic Oils Ltd. was formed in 1967, financed 55% by industrial companies and 45% by the Federal Government. The government's share is now administered by Petro-Canada [30].

The first major discovery in the Arctic Islands was made by Panarctic at Drake Point in 1969. Later discoveries were made onshore at King Christian Island, Ellef Rignes, and Hecla (Figs. 6-16, 17) in the early 1970's. The first offshore well on an ice-strengthened platform was the Panarctic Hecla N-52, 11 km from the shore in 128 m of water (Fig. 6-16), drilled in 1974. In 1976 the first totally offshore gas field was found at Jackson Bay (Fig. 6-17) [14].

Panarctic land holdings, in which Petro-Canada has interests, are shown in Figs. 6-16, 17 and consist of nearly 77 MM acres, mainly onshore. These figures also show 33 MM acres, mainly offshore, acquired by the Arctic Islands Exploration Group (AIEG), in 1976. This group includes Panarctic Oils, Petro-Canada, Esso Resources Canada Ltd., and Gulf Canada Ltd. The acreage was acquired from Sun Oil Company Ltd. and Global Arctic Islands Ltd. in return for a commitment to spend $80 million during a 5-year period in the highly-prospective offshore region [14].
Figure 6-16: Land holdings of western Arctic Archipelago.
Figure 6-17: Land holdings of Eastern Arctic Archipelago.
Arctic sediments have been deposited in two major basins: the Franklinian and Sverdrup (Fig. 6-18). The structural provinces and tectonic map (Fig. 6-19) show the Franklinian and Sverdrup basins [65].

Exploration-prospect opportunities within the Franklinian and Sverdrup basins are summarized on the diagrammatic N-S and E-W structural cross-section (Fig. 6-20). The Franklinian Basin extends more than 2,400 km from Greenland to Bank Island as shown on the paleogeographic map (Fig. 6-21) [65].

In the Franklinian Basin the principal reservoir targets are the Ordovician, Silurian, and Devonian reef carbonates within the Melville, Banks and Ellesmere areas (Fig. 6-22). In the Sverdrup basin the principal reservoir targets are the Cretaceous, Triassic, Jurassic, and Pennsylvanian sandstones in the Melville and Ellef Rignes areas (Fig. 6-23) [65].

A paleogeographic map and facies cross-section of the potential Lower-Middle Triassic within the Sverdrup basin is shown in Fig. 6-24. A S-N structural-stratigraphic cross-section of the Drake Point field in the western Sverdrup basin is illustrated in Fig. 6-25 [65].

Basin-margin truncation traps also provide potential oil and gas prospects in the western Sverdrup basin on the Prince Patrick uplift below the Borden Island (Figs. 6-26, 27) [65].

Significant oil and gas occurrences in both the Franklinian and Sverdrup basins are summarized on Figs. 6-28 and 29. The Bent-Horn oil field, which was discovered in 1974, on Cameron Island has wells capable of flow rates up to 5,000 b/d, but the reservoir volume is small [14].
Figure 6-18: The Sverdrup and Franklinian sedimentary basins.\textsuperscript{65}

Figure 6-19: Structural provinces in the Arctic Islands.\textsuperscript{65}
Figure 6-20: Sverdrup and Franklinian cross-sections.

Figure 6-21: Paleogeographic map of the Franklinian basin.
Figure 6-22: Franklinian basin stratigraphic column.

Figure 6-23: Sverdrup basin stratigraphic column.
Figure 6-24: Paleogeographic map of Sverdrup basin.

Figure 6-25: Structured stratigraphic cross-section of Drake Point field.
Figure 6-26: Sverdrup basin, Prince Patrick uplift area.65

Figure 6-27: Sverdrup basin, Prince Patrick uplift prospects.65
Figure 6-28: Oil occurrences of the Canadian Arctic Islands.\textsuperscript{14}

Figure 6-29: Gas occurrences of the Canadian Arctic Islands.\textsuperscript{14}
The first seven fields, including the 1965 Drake Point discovery, found 12 tcf of gas of which 90 percent is reservoired in Borden Island and King Christian Island sandstones. Two fields, Drake and Hecla, contain 70 percent of the gas, which accounts for approximately 9 of the 12 tcf. The remaining 25 percent is in five fields in the Ellef Ringnes area (Fig. 6-29) [14].

Drake Point and Hecla are giant fields having 5.3 and 3.6 tcf in estimated reserves which is deposited in deltaic sandstones (Fig. 6-30). The Drake trap on the electric-log cross-section (Fig. 6-31) shows the Borden Island truncated at the top and the base. The Drake field, with six onshore and two offshore wells, is 10 x 30 km in size, and pay sandstones 10-30 m thick. Hecla, with three onshore and four offshore wells, is 13 x 30 km, with net pays of 8-35 m [65].

Fields in the Ellef Ringnes Island area are smaller than those of the Melville Island area. The size averages about 5,000 acres, and the structures have much higher relief (Figs. 6-32, 33). The reservoir sandstone is 10-15 times thicker than at Drake and Hecla (up to 600 m thick). Ellef Ringnes structures are estimated to contain 3.1 tcf in five fields. Net pays range in thickness from 20 m at Thor to 175 m at Jackson Bay in gas legs ranging in thickness from 50-260 m. The fields, which are both onshore and offshore, have reserves ranging from 100 Bcf to more than 1 Tcf. Exploratory and delineation wells have been drilled on ice platforms in water depths up to 365 m [35].

Figs. 6-34 and 35, from the Drake F-16 and King Christian N-06 wells, compare the Melville and Ellef Ringnes-type pay zones.
Figure 6-30: Gas fields in the Melville Island area.65

Figure 6-31: Electric log cross section of the Drake Point gas field.65
Figure 6-32: Gas fields of Ellef Ringnes Island area.65

Figure 6-33: Structural-stratigraphic cross section of the King Christian gas field.65
Figure 6-34: Drake Point gas field, well F-16.
Figure 6-35: King Christian gas field, well N-06.
Drake F-16 well consists of 35 m of gross pay, and 21 m of net gas pay with a calculated open-flow rate of 265 MMcf/d. In Ellef Ringnes King Christian N-06, the gas sandstone has 121 m of net pay having a calculated flow rate of 410 MMcf/d [18].

In 1979, an eighth gas field, Whitefish (Fig. 6-29), was discovered. Whitefish was drilled by the Arctic Islands Exploration Group (Panarctic, Petro-Canada, Esso Resources, and Gulf Canada) and partners. The Whitefish H-63 discovery well tested gas from the King Christian Island reservoir at a rate of 8,100 MMcf/d with a spray of light condensate. The Whitefish confirmation well G-63 (in 275 m of water) was drilled in 1980 about 300 m from the H-63 discovery. The Whitefish G-63 well (Fig. 6-36) confirmed the presence of significant hydrocarbons in two zones shallower than the King Christian Island sandstone. The three zones were tested at 7.5, 14.5, and 44 MMcf/d, respectively. Liquid condensate separated from the gas averaged 13-17 bbl/MMcf [14].

In addition to the Whitefish confirmation well, significant hydrocarbon recoveries were announced at two other offshore wildcats drilled in the Sverdrup Basin during the 1980 winter drilling season. The two discovery wells were the Panarctic-Dome-A106 Char G-07 and its sister wildcat Panarctic-A106-Dome Balaena D-58 (Fig. 6-29) [14].

Char G-07 was announced as a second discovery of the 1980 drilling season. This well was drilled on an ice platform in 262 m of water and flowed gas at rates up to 18 MMcf/d. A test of a deeper zone flowed gas at 2 MMcf/d and also recovered a small amount of oil [18].
Figure 6-36: Whitefish G-63 and Drake F-76 wells.  

Figure 6-37: Offshore seismic coverage in the Arctic Islands.
Balaena D-58 was drilled from an ice platform in 237 m of water and flowed gas at a rate of 3 MMcf/d and recovered a small amount of light gravity crude oil. The hydrocarbons encountered in the Balaena test were not considered large enough to warrant commercial production [18].

The greatest potential for new Sverdrup discoveries is in the untested offshore, which is more than 60 percent of the basin (Fig. 6-37). The Arctic Islands Offshore Group, a consortium of 11 companies, has acquired more than 16,000 km of seismic data as shown by Fig. 6-37. These data were obtained during annual winter sea-ice seismic programs during the years 1975-78 at a gross cost in excess of $40 million [31].

In the untested offshore Sverdrup basin, trap types similar to both the Drake-Hecla combination stratigraphic-structural fields and the high relief Ellef Rignes anticlinal gas pools have been defined. Potential traps exist on salt domes, both on the flanks or in closures over the tops. Other potential traps may include untested fault controlled structural closures (Fig. 6-38) [65].

The parameters for the discovered Sverdrup gas fields are shown on Table 4. The potential gas reserves for the Sverdrup basin are shown on Table 5 [65].

Offshore structures are economic to develop individually if they contain reserves of 500 Bcf - 1 tcf. This is because of the high capital costs including: drilling costs up to $13 million for each exploratory test, and major offshore flowline and completion costs ranging up to $500 million per field. Total capital investments could be more than $1 billion for the larger
Figure 6-38: Sverdrup basin trap types.
**DISCOVERED GAS RESERVES**

**ONSHORE AND OFFSHORE SVERDRUP BASIN**

**MESOZOIC FIELDS**

<table>
<thead>
<tr>
<th>FIELD TYPE</th>
<th>ANTICLINAL (ELLEF RINGNES FIELDS)</th>
<th>COMBINATION (DRAKE - HECLA FIELDS)</th>
<th>ALL FIELDS</th>
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<tr>
<td>AREA - ACRES</td>
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<td>85,000 - 103,000</td>
<td>3,500 - 103,000</td>
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<td>132 - 160</td>
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<td>AREA - SQUARE KM</td>
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<td>345 - 418</td>
<td>14 - 418</td>
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Table 4: Discovered gas reserves, offshore and onshore.

**POTENTIAL GAS RESERVES**

**OFFSHORE SVERDRUP BASIN**

**UNTESTED MESOZOIC PROSPECTS**

<table>
<thead>
<tr>
<th>TRAP TYPE</th>
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<td>GROSS RESERVES (TCF)</td>
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Table 5: Potential gas reserves.
Figure 6-39: Air-cushioned drilling system.18
offshore gas fields. Despite these costs, more than two-thirds of the potential reserves are believed to be in giant offshore structures that can be developed economically. With more than approximately 16 tcf discovered, and pipeline requirements of 25-30 Tcf, sufficient gas discoveries will most likely be found in order to justify the construction of an Arctic pipeline [15].

Annually, about 3-4 wildcats are drilled with Petro-Canada participating in the majority of these. Petro-Canada also participates with industry in the development of new offshore drilling and production technology. Offshore drilling in the Arctic Islands has involved a unique method of drilling with a modified conventional rig on a 5 m thick artificially strengthened sea-ice platform, constructed by pumping and flooding the ice surface with sea water. Only minimal lateral ice movement can be tolerated. Westburne-Hi-Tower Rig No. 1, constructed in 1977, was specially designed for ice-platform drilling and for installation of underwater wellhead completion equipment and flow lines in deep water [18].

Because drilling depths exceed present 1982 capability in the central Sverdrup basin, and since ice motion exceeds tolerable limits in parts of the basin, improved drilling technology will be required. Petro-Canada in 1978, considered the feasibility of an air-cushioned drilling system which could be towed to the drillsite with an accompanying barge in which the necessary fuel, supplies, and telecommunications equipment could be housed. The barge could be used in emergencies as a pad for a relief well (Figs. 6-39, 40) [18].
Figure 6-40: Concepts for Arctic production.\textsuperscript{18}
New underwater gas-well completion technology was pioneered during 1978 by Panarctic, Petro-Canada, and Alberta Gas Trunk Line Ltd. The Drake F-76 development well (Fig. 6-36) was drilled with the Westburne-Hi-Tower Rig in 60 m of water, 1.5 km offshore in the Drake Point field. It was completed using a diverless procedure in which the flow line bundle was winched and swung into locked position on a wellhead installation on the seafloor. This was completed successfully in April 1978 with flows in excess of 70 MMcf/d [14].

The offshore Sverdrup basin, with large traps, thick reservoir beds, and excellent source rocks, has the potential to become one of the world’s major producing basins. In this harsh and delicate environment, operating conditions will continue to challenge technological capability. However, the basin potential of 125 tcf justifies the continued research, as well as the high capital requirements to transport the discovered gas and oil reserves to southern markets economically [65].

Dome is developing a unique swivel drillship (Fig. 6-41) or ice-drilling barge which has been fully model-tested and would permit extended drilling operations. The mooring system would permit the drillship always to turn its ice-reinforced bow in the direction of advancing ice and reduce tensions on anchor chains [14].

The Arctic Isles contain enough gas to justify the implementation of both LNG and BMMP schemes. The new barge-mounted mineral processing plant on Little Cornwallis Island demonstrates that BMMPs can be transported and operated in the Arctic [51]. Tankers similar to those used in the Arctic Pilot Project can be
used to transport methanol to markets in Eastern Canada and/or Europe. Tanker transportation is described in detail in Section E of this thesis.
Figure 6-41: Dome's concept of new Arctic drill barge.
C. The Polar Gas Project

Canada's Arctic frontier, consisting of the coastal regions in the Northwest Territories and the Yukon, as well as the Arctic Islands, shows great potential. Fig. 6-42 indicates the potential promise of this frontier area [44].

More than 20 Tcf of marketable reserves have already been proven, and this figure increases with every new drilling season [40].

A number of transportation modes have been examined for bringing natural gas out of the frozen Arctic and south to consumer markets. Fig. 6-43 shows the comparative energy efficiencies of these various modes [49].

Studies indicate that LNG tankers would be approximately 80 percent efficient once conversion losses (liquification and gasification) and fuel requirements (ice navigation and ocean transportation) have been considered [49].

The most efficient mode of transporting natural gas from the Canadian Arctic is via large diameter buried pipeline in which the energy transmission efficiency approaches 95 percent [44].

The Polar Gas Project proposes to build a "combination" pipeline system that connects southern markets to two major gas areas on the Northern frontier, the MacKenzie Delta and the Arctic Island (Figs. 6-44, 45) [49].

Fig. 6-46 shows how separate laterals from each area will be "combined" into a single pipeline in the vicinity of Great Bear Lake. This "Y" line configuration will provide natural gas
Figure 6-42: Potential Arctic gas reserves.\textsuperscript{44}

Figure 6-43: Energy efficiency of alternate modes of transporting Arctic Island gas.\textsuperscript{49}
Figure 6-44: Current Arctic natural gas discoveries.\textsuperscript{49}
Figure 6-45: Arctic Island natural gas discoveries.
Figure 6-46: Proposed Polar Gas Y Line.\textsuperscript{44}

Figure 6-47: Proposed channel crossings.\textsuperscript{44}
transmission to markets in Ontario, Quebec, and the northeastern United States [44].

The main pipe will be 106 cm diameter, while the Delta and Island laterals will be 75 cm and 90 cm, respectively. The entire system will be capable of operating at a pressure of 1,680 psig, and will ultimately deliver 3.3 Bcf/d of natural gas to Longlac, Ontario [44].

Under this proposal, almost 5,000 km of pipe will be laid. Current schedules call for initial gas flows from the MacKenzie Delta within 4 years, and completion of all work within 5 years from the start of construction [73].

A total of 52 rivers must be crossed, including three "major" and 21 "intermediate" crossings. Less than two km of pipeline will require protection against frost heave at these rivers. Studies show that none of the land-based pipeline will be susceptible to frost heave, since the gas will be refrigerated below 32°F throughout the continuous permafrost region of some 2,700 km in length [73].

Over the remainder of the route, conventional warm gas transmission (above 32°F) will be used [73].

Major engineering interest in the Polar Gas Project centers upon the two marine crossings of the Islands lateral (Fig. 6-47) [44].

The marine pipeline crossings lie at the north and south ends of Victoria Island. Because of the diverse conditions encountered at these two locations, quite distinct construction techniques will be adopted at each site [63].
The easiest crossing is at Dolphin and Union Strait lying between Victoria Island and the mainland. The strait is 30 km wide, with a maximum depth of 120 m. Winter ice thickness here averages approximately two m, but summer usually provides about three months of open waters [44].

Because of the narrow channel and relatively long ice-free season, conventional laybarge techniques are planned for pipeline across this channel. All construction materials will be barged to the site via Arctic waterways, and the pipeline will be assembled and lowered from a modified conventional laybarge similar to those used in many parts of the world [63].

The second marine crossing, between Victoria and Melville Islands, is more formidable. M'Clure Strait is 120 km wide, 500 m deep, and winter ice thickness varies from 2 to 12 m. Considerable ice accumulations generally persist through the summer [44].

The limiting environmental factors at M'Clure are the variability in ice thickness and the absence of a predictable weather "window" for ice-free conditions. Accordingly, marine construction in the strait is not feasible using either laybarge or a continuous trench cut through the ice surface. [73]

After several years of intensive study, it now appears that marine pipelines can be laid across M'Clure Strait with the "Ice Hole Bottom Pull" method developed by the Polar Gas Project [44].

Conceptually, the Ice Hole Bottom Pull method is quite straightforward. Long pipe strings are pulled into place on the bottom of M'Clure Strait from a series of holes cut into the ice
surface. Practically, however, the application of the concept is much more involved [44].

The Ice Hole Bottom Pull method begins with the establishment of a "make up" yard for pipe welding on the south shore of M'Clure Strait. Holes are cut into the ice at regular intervals across the strait, and large "pull units" are set up at these holes to pull the pipe out of the make-up yard and under the ice (Figs. 6-48, 49) [40].

Pairs of pull units advance the pipe a fixed distance along the bottom. Then the "pull cable" is released from the units and lowered back to the seabed before the units at the next ice station can take over the pulling operation. The released units are subsequently demobilized and moved ahead for use in a later "pull sequence" (Fig. 6-50) [44].

After each section of pipe has been pulled into the water, another section is welded to the first while the pull units are being prepared for the next pull sequence. When the final section has been added, the entire string is pulled across the bottom of M'Clure Strait towards the north shore (Fig. 6-51) [44].

Two identical pipelines will be laid across the 125 km width of M'Clure Strait. Both will be constructed of 90 cm diameter pipe [44].

Several variations of the basic method are possible. In the "cable-on-bottom" option of Fig. 6-52, an endless loop pull cable, lying on the seabed, supplied half of the necessary pull force. The other half is provided by cable pull units [59].
Figure 6-48: Ice hole cable pulling unit.40

Figure 6-49: Cable pulling unit.40
Figure 6-50: Cable lowering procedure.44
Figure 6-51: Cable pulling configuration.

Figure 6-52: Cable on bottom option.

Figure 6-53: Extended reach option.
Under the "extended reach" option of Fig. 6-53, buoys are used to reduce the effective weight of submerged cable, which permits greater lengths of cable to be extended in the water. While this option may reduce the number of ice holes required, it also requires considerable extra rigging [59].

On-ice construction begins with the siting and placing of ice holes. Stations are located about two km apart. As each hole is cut, an insulating liner is inserted and connected to a separate utility unit. This unit contains a heat exchanger which pumps coolant through small pipes in the liner, thereby maintaining ice-free conditions inside the hole while keeping the surrounding ice surface intact (Fig. 6-54) [44].

There are several connection technologies available for marine tie-ins. Mechanical connections have, to date, been used principally in relatively shallow waters. Surface tie-ins, raising the pipe to the surface for welding, are not ideally suited to the heavy ice surface and deep water of M'Clure Strait [40].

The most practical connection procedure for this project is to weld pipe strings together on the seabed. One of the principal methods in this category is hyperbaric welding, which takes place at local bottom pressure [40].

For the 500 m depths of M'Clure Strait, welders would be subject to 50 times normal atmospheric pressures, and consequently would require decompression periods on the order of 2 weeks after such dives [40].

It is currently anticipated that an alternative approach, the "one-atmosphere" method, will be employed at M'Clure Strait.
Figure 6-54: Ice hole installation.

Figure 6-55: Pipeline connection on sea bed.
Since such welds are made at standard pressure, this method permits divers to resume normal activity immediately upon return to the surface. A brief description of this technique follows [44].

The two on-bottom pipe strings are initially aligned with an acoustic beacon and lifted onto laterally moving H-frames for final alignment via a template. A series of surface-controlled tools are then used to strip, cut, clean, and plug the pipe ends. A manned submersible remains in the vicinity throughout these operations for observation, direction, and possible assistance in the event of difficulties [44].

The one-atmosphere "welding habitat" is then lowered from the surface, and its articulated hemispheres are clamped around the pipe ends (Fig. 6-55) [44].

Sea water is purged from the inside of the habitat and a crew descends from the surface in a transfer module. Once inside the habitat, the men proceed to finish the pipe ends and complete the weld [44].

After the weld has been satisfactorily X-rayed, the crew reenters the transfer module and is returned to the surface. Finally, the habitat itself is recovered and removed to the next tie-in location [44].
D. Beaufort Sea BMMP Proposal

In the normal course of events, natural gas and crude oil from this area would be transported to markets when the amounts discovered justified suitable transportation systems. While various tanker schemes have probably been looked at, we shall only consider here pipelines going ashore and then south or southeastward through the Mackenzie River Valley into Alberta. Here they would either connect to other pipelines already operating or else new ones would loop older ones to bring the hydrocarbons to markets in the US or Canada.

In the Northwest Territories and northern Alberta, the pipelines would go through a heretofore untouched region, a good deal of which is underlain by permanent of intermittent (seasonal) permafrost. The same condition exists in Alaska and had a major impact in the mid-1970s on the construction and costs of the Alyeska Pipeline now carrying oil. Because this carries hot crude oil, almost half of it had to be built on very expensive supports raising the pipeline a few feet above the ground’s surface to prevent thawing of the permafrost. Construction experience showed that it actually cost about three times as much to install this pipeline on these supports as it did to be put in an otherwise comparable non-permafrost area.

For various reasons, it is not possible to transport both crude oil and its associated natural gas for long distances in the same pipeline, and hence two separate and distinct ones are generally used. This problem, together with those associated with permafrost, lead to the development almost a decade ago of an alternate method of transportation of both the oil and the
modified gas in a single completely buried pipeline built in permafrost regimes [40,51]. Unfortunately, this method was developed too late for serious consideration in Alaska although it would have lead to considerable cost savings in the Alyeska line and would also have prevented the current dilemma over the Alaska Natural Gas Transportation System (ANGTS).

In brief, the method involves conversion of the natural gas to methanol by processes described earlier in this thesis and then dispersion of the crude oil in the methanol to form a fluid which is superficially something like an emulsion of oil-in-water. Both mechanical energy and special chemical stabilizing agents are required to achieve the dispersion. After the dispersion is cooled to temperatures below 0°C, it can be pumped in a single, completely buried pipeline. While there are the additional capital costs for the BMMPs, the dispersing equipment, and the refrigeration equipment, there are considerable savings from building one instead of two pipelines and from having it entirely buried rather than partially built on expensive supports.

We are proposing here that this approach be seriously considered for bringing the Beaufort Sea hydrocarbons to pipelines and markets further south. To support this proposal, we have carried out a preliminary economic analysis using cost and productive capacity data already published. For fields already discovered and tested, it is believed that we can produce 1.7 MMB/D of crude oil and 1.5 to 2.5 Bcf/d of natural gas. For the latter, we shall use the average of 2.0 Bcf/d in our calculations. As
described in earlier chapters, the latter can be converted to 475 MB/D of methanol.

For either transportation system, we shall assume that the offshore fields are drilled up by the same method and that oil and gas have been separated and brought ashore to the Mackenzie River delta area by suitable pipelines (Figure 6-56). This onshore terminal is the starting point for comparison of the two alternate transportation systems and Medicine Hat, Alberta is the pipeline terminal in the south. To the extent that we can, we shall compare both the capital and operating costs of the two systems.

Let us consider the two pipeline system initially and the oil pipeline first. It will traverse about 960 km through various kinds of permafrost to approximately Norman Wells, N.W.T., and then about 2560 km to the terminal at Medicine Hat, Alberta. For the former it would have to be built on supports above ground and for the latter it should be buried. We have used data presented by Hooker for these cost estimates for Alaska and have assumed a price escalation of 10% per year from 1975 to 1982. This is a conservative estimate because the terrain in Canada is far less rugged than the mountains of Alaska and the diameter of the Canadian pipeline may be slightly smaller than the 48-inch Alyeska line. With current cost estimates of US$16.6 MM and US$5.5 MM per kilometer, the construction costs for the two segments are $15.9 billion and $14.1 billion. These as well as the results of subsequent calculations are presented in Table 6.

The natural gas obtained from field separators must be conditioned or converted into a "pipeline quality gas" before it
Figure 6-56: Proposed Beaufort-Alberta pipeline system.73
<table>
<thead>
<tr>
<th>(in $ Billions)</th>
<th>Oil</th>
<th>Gas</th>
<th>Dispersion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Cost, pipeline:</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Permafrost Region</td>
<td>15.9</td>
<td>13.0</td>
<td>13.3</td>
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<tr>
<td>Non-permafrost Region</td>
<td>14.1</td>
<td>12.0</td>
<td>11.8</td>
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<tr>
<td>Gas Conditioning Plant</td>
<td>--</td>
<td>6.0</td>
<td>--</td>
</tr>
<tr>
<td>BMMPs</td>
<td>--</td>
<td>--</td>
<td>7.0</td>
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<tr>
<td>Dispersion</td>
<td>--</td>
<td>--</td>
<td>0.4</td>
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<tr>
<td>Initial Refrigeration</td>
<td>--</td>
<td>--</td>
<td>0.5</td>
</tr>
<tr>
<td>TOTALS</td>
<td>30.0</td>
<td>25.0</td>
<td>33.0</td>
</tr>
<tr>
<td>Sum of Oil plus Gas</td>
<td></td>
<td></td>
<td>55.0</td>
</tr>
<tr>
<td>Net difference between oil-gas</td>
<td></td>
<td></td>
<td>22.0</td>
</tr>
<tr>
<td>and dispersion alternatives</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
can be transported in a large, high pressure pipeline. This involves removal of condensibles (hydrocarbons other than methane and ethane) and corrosives (principally hydrogen sulfide). The Ralph M. Parsons Company has recently estimated the cost of such a plant of this capacity for Prudhoe Bay at $6 billion [51].

While a more detailed comparison involving the composition of the two kinds of gas may modify this figure somewhat, we shall use it here as a reasonable approximation. Because field gas can be run directly into BMMPs unless it contains significant amounts of hydrogen sulfide, such a gas conditioning plant is not needed for this other alternative.

Next the gas must be refrigerated and maintained at below 0 °C if it is to be transported through permafrost in a completely buried pipeline. While some design work was done on this in the 1970s for the proposed Arctic Gas Project, the results are not now available to us. But we do know that the Alaskan segment of ANGTS is about 1120 km long and traverses mostly permafrost. Conservative estimates have put its cost at $30 billion in as spent dollars or $13.7 MM per kilometer. For the 960 km of permafrost along the Canadian line, this comes to $13.0 billion. The cost estimate for the 1280 km segment of the ANGTS in Alberta is $6.0 billion or $4.7 MM per kilometer and this is used to get total construction costs of $12.0 billion for the non-permafrost segment of the gas line. Because of differences in terrain in Alaska and Canada, these estimates are also believed to be on the conservative side.

Now for consideration of the single pipeline concept. BMMPs having a productive capacity of 3000 metric T/d, (23,670 bbl/d)
consume almost 100 MMcf/d of natural gas and cost about $330 million in current US dollars delivered. These would be either moored in channels of the Mackenzie River delta, beached or sunk onto piles in excavated basins. For conversion of all the gas to methanol, we estimate 21 BMMFs costing a total of $7.0 billion would be required. Construction of these is estimated to require 28 months each so they would have to be built and delivered in batches while the pipeline is being constructed.

If all of the gas was converted to methanol initially, then we would have 475 Mbbl/d which, when combined with the 1600 Mbbl/d of crude oil, would provide dispersions containing 30% methanol. Those containing 70% crude oil and below were found to be completely stable and so it may not be necessary to convert all of the gas to methanol. The desirability of doing so will depend on the other possible uses for the gas and the market for methanol.

Equipment is needed both to prepare the crude oil dispersions in methanol and to cool them. Cost estimates for these made by Hooker in 1975 have been adjusted both for the somewhat different capacities in the Alaskan and Canadian systems and for an assumed price escalation of 10% per year to 1982.

Because both the crude oil dispersed in methanol pipeline and the natural gas pipeline would be completely buried, operate cold and be about the same diameter, we have assumed their construction costs would be the same. This would, of course, include the refrigeration equipment cost which was calculated separately by Hooker [40].
The sum of the construction costs for the oil plus gas transportation systems are compared in Table 6 with those for the crude oil dispersion in methanol system. It is apparent that there would be an appreciable saving of approximately $22 billion achieved by using the latter.

Because only one pipeline would be needed instead of two and none built on above-ground supports, there would be considerably less environmental impact. That from the BMMPs would be about the same as that from the gas conditioning plant.

The operating expense for the O/M dispersion system was determined from the operating expenses of the methanol synthesis plant, the refrigeration units, the mechanical mixers, and the dispersant cost.

Each operating expense was determined with the assumption of a 12% rate of return on investment after taxes. Straight-line depreciation for a 20-year project life was used in the calculations. The cost of fuel was assumed to be $2.25/MM Btu (escalated at 10% per year after 1975).

The incremental operating expenses for the modified Beaufort-Alberta Pipeline are listed in Table 7. The BMMPs have an operating expense of $1.51/MBtu of methanol produced, which is 80% of the total operating expense of the O/M dispersion system. The dispersant cost and refrigeration units operating expense each have approximately the value of $0.15/MBtu of methanol transported, while the operating expense of the mechanical mixer is negligible. The additional fuel consumption of the O/M dispersion system costs $0.09/MBtu of methanol transported. Therefore, the total operating expense of the O/M dispersion
TABLE 7

The Operating Expense of the Modified Beaufort-Alberta Pipeline for a 2.0 MMB/D Flow Rate of 70% Dispersions

<table>
<thead>
<tr>
<th>Component</th>
<th>Operating Expense $/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methanol Plant *</td>
<td>3.10</td>
</tr>
<tr>
<td>Dispersant *</td>
<td>0.40</td>
</tr>
<tr>
<td>Refrigeration Units *</td>
<td>0.40</td>
</tr>
<tr>
<td>Mechanical Mixers *</td>
<td>0.140</td>
</tr>
<tr>
<td>Pumping *</td>
<td>0.086</td>
</tr>
</tbody>
</table>

* Based on 1975 estimates from Hooker's [40] Dissertation, escalated at 10% per year.
TABLE 8

Operating Cost Estimates for Alternate Transportation Systems

(1982 U.S. dollars)

<table>
<thead>
<tr>
<th></th>
<th>Oil ($/MMBtu)</th>
<th>Gas ($/MMBtu)</th>
<th>Dispersion ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expense</td>
<td>1.60 *</td>
<td>1.50 *</td>
<td>3.50 *</td>
</tr>
<tr>
<td>Sum of Oil plus gas</td>
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<td></td>
</tr>
<tr>
<td>Net difference between Oil-gas and dispersion</td>
<td>0.40</td>
<td></td>
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</table>

* Based on 1975 estimates from Hooker's [40] dissertation, escalated at 10% per year.
system was $1.90/MMBtu of methanol synthesized and transported in the modified Beaufort-Alberta pipeline system.

The operating expense of the two proposals are presented in Table 8. The combined oil-gas pipeline system has an estimated operating expense of $3.10/MMBtu, while the D/M dispersion system has a higher estimated operating expense of $3.50/MMBtu. However, given the uncertainty in these estimates, these costs are essentially the same.
E. The Arctic Pilot Project

The Arctic Pilot Project is designed to test the feasibility of producing natural gas from wells in the Arctic Islands, transporting the gas by a 160 km buried pipeline, transforming the gas into liquified natural gas (LNG) and shipping the LNG by ice-breaking carrier to a regasification plant in southern Canada. This will be implemented on a year-round basis.

The project has been called a pilot because it is designed at the minimum scale necessary to prove the technical and economic feasibility of delivering Arctic Islands natural gas by ship. It will be one-tenth the size of any full-scale alternative for the delivery of Arctic gas. Even though the project is small in scale, it offers substantial benefits for transportation and industrial development, job creation and access to frontier resources (Fig. 6-57).

Petro-Canada initiated the project in 1976 as a way to stimulate frontier exploration and to increase Canadian energy supply. The other participants in the project are NOVA, an Alberta corporation; Dome Petroleum Ltd.; and Melville Shipping Ltd. [2].

The supply of gas for the project will originate from the Drake Point gas field on the northern Sabine Peninsula of Melville Island. (Fig. 6-58). Presently, reserves in the field are in excess of 150 billion cu m [2].

Panarctic Oils Ltd. will own and operate the production wells, the gathering system and other facilities to produce the 60 billion cu m of gas required during the 20-year life of the project [2].
### MID 1985 START-UP

<table>
<thead>
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<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
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<tr>
<td>LNG Plant Delivery and Tie-In</td>
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<td>Dehydration Facilities Construction and Tie-In</td>
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Figure 6-57: Master construction schedule for the APP.¹
Figure 6-58: General plan for APP implementation.²

Figure 6-59: Bridport terminal facilities.¹
From the Drake Point field, the gas will be carried south 160 km by a 56 cm diameter pipeline across Melville Island to the liquefaction plant at Bridport Inlet [2].

Since Melville Island is in a zone of continuous permafrost, a buried chilled gas pipeline will be used over the entire route. The gas flowing into the pipeline will be chilled to $-6^\circ C$ to preventing melting of the permafrost.

Bridport Inlet, on the southern coast of Melville Island, is a 93 sq km natural harbor. In this location natural gas will be liquefied and temporarily stored before being loaded onto the ships for the 5200 km journey south (Fig. 6-59). Petro-Canada will manage the design, construction and operation of the Bridport liquefaction, storage and loading portion of the product [1].

The natural gas will be liquefied in a series of steps in which it is cooled to about $-162^\circ C$. During this liquefaction process each 600 cu m of natural gas is reduced to about 1 cu m of LNG, resulting in a very compact energy source [2].

The LNG plant and storage tanks will be barge-mounted. It is planned that the three barges will be built in southern Canada where control over costs and construction schedule can be effectively maintained. The barges will be towed to Melville Island and installed there as part of the Bridport facilities [17].

There will be four storage tanks which will contain up to 200,000 cu m of liquefied natural gas. The two storage barges eliminate problems of changing draft as the tanks are filled or emptied [4].
The two ships carrying the LNG to southern markets will be among the most sophisticated and powerful commercial vessels ever built. They will be the world’s first LNG-carrying ships with ice-breaking capabilities. Each ship will be 395 m in overall length with a beam of 50 m and will have a draft of 11.5 m in open water, 18 m in ice (Figs. 6-60, 61, 62, 63) [1].

The route to be taken by the ships has been carefully studied for several years using satellite imagery and on-ice surveys. The historic size, location and number of icebergs and ice pressure ridges have been taken into account in designing a route that will optimize fuel consumption without adversely affecting the environment (Figs. 6-62, 64, 65, 66) [1].

Propulsion for the ships will be provided by a combined gas turbine/steam system, which makes full use of the LNG cargo boil-off which occurs naturally on all LNG vessels. This boil-off occurs as a result of heat flow from the environment to the relatively cold cargo, causing a small percentage of the LNG to vaporize. The use of gas as a fuel source makes the carriers non-polluting energy transporters [16].

Each ship will have two crews of 42 persons who will alternate voyages. Return voyages are estimated to take 33 days in winter and 16 days in summer. A total of 16 trips per ship per year will be made [16].

The ships will be fitted with the most up-to-date radio and satellite communications equipment. Advanced radar and ice detection systems will be included along with dynamic positioning equipment [16].
Figure 6-60: Arctic LNG ship.

Figure 6-61: Arctic LNG ship (top view).

Figure 6-62: Arctic LNG ship (cross section).

Figure 6-63: Arctic LNG ship (side view).
Figure 6-64: APP proposed route for LNG ships.\(^1\)
Figure 6-65: Northern preferred operational corridor.¹
Figure 6-66: Southern preferred operational corridor.
All LNG ships have double hulls in order to protect the containment systems. The APP ships will extend this concept by having double hulls throughout and by strengthening the outer hull and support members to withstand the ice loads to be encountered. Travel through ice will be at a reduced speed to further enhance the safety of operations [16].

The APP participants and TransCanada Pipelines (TCPL) have undertaken extensive studies of the potential terminal sites in Eastern Canada. After careful review of all factors, there are two possible sites for the location of these facilities: one is at Gros Cacouna in the Province of Quebec, and the other at the Strait of Canso in the Province of Nova Scotia. Both locations are acceptable to the sponsors on the basis on environment, socio-economics, shipping capability and public safety (Figs. 6-67, 68) [1].

At the location of the terminal, TCPL will construct and operate the unloading dock, storage tanks, revaporization equipment and fully instrumented control facilities. Nearby will be office space for the land-based, carrier support staff [1].

The LNG will be unloaded from the ships into two 100,000 cu m storage tanks. This liquid will be converted to a gas which will be distributed to the market via conventional pipelines (Fig. 6-69) [1].

If regulatory approval for the project is received early in 1982, delivery of Arctic gas will begin in late 1985 or early 1986. This gas will be sold to Eastern Canadian customers at the prevailing local price. In exchange, Western Canadian gas, which would be pipelined east to supply this market, will be displaced
Figure 6-67: LNG loading terminal, Bridport Inlet, N.W.T.¹

Figure 6-68: LNG receiving terminal, Quebec or Nova Scotia.¹
### CAPITAL AND OPERATING COST SUMMARY

(Stated in millions of 1980 Canadian dollars)

<table>
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<tr>
<th>PROJECT COMPONENT</th>
<th>CAPITAL</th>
<th>OPERATING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Melville Island Pipeline</td>
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<td>1.7</td>
</tr>
<tr>
<td>Bridport LNG Facilities</td>
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<td>25.3</td>
</tr>
<tr>
<td>Marine Transportation</td>
<td>529.9</td>
<td>41.3</td>
</tr>
<tr>
<td>Project Administration and</td>
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<td>10.0</td>
</tr>
<tr>
<td>Research and Development</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>SUB TOTAL</strong></td>
<td>1,325.3</td>
<td>78.3</td>
</tr>
</tbody>
</table>

| ASSOCIATED FACILITIES                     |          |           |
| Drake Point                               | 157.6    | 12.2      |
| Southern Terminal                         | 173.6    | 3.5       |
| **SUB TOTAL**                             | 331.2    | 15.7      |
| **GRAND TOTAL**                           | 1,656.5  | 94.0      |

Table 9: Capital and operating cost summary.\(^1\)

---

**Figure 6-69: LNG regasification terminal.**\(^{16}\)
and sold to customers in the U.S. at the prevailing current border price. The APP estimates the delivery to the U.S. group of 7.4 cu m/d (260 MMcf/d), which is approximately 12 percent of current Canadian gas exports to the U.S. [17].

The safety of the Arctic Pilot Project will be enhanced by the following features:

1. The strength of the structural design, the high level of propulsive power and the superior manoeuverability of the icebreaking carriers.

2. The safety distance from the coastlines and population centers which will be maintained by the carriers.

3. Choice of location for the terminal facilities, both in the north and south, well removed from densely populated areas.

4. The use of highly trained personnel, concerned and aware of the need for the highest standard of safety at all times.

5. Design standards exceeding the current safety requirements imposed or recommended by Canadian regulatory authorities.

The project is scheduled to be completed by mid-1985. The total capital cost is estimated to be $1.5 billion Canadian dollars (1980). The cost of Drake Point field development will be an additional $157.6 million which will be expended by Panarctic Oils Ltd. The southern terminal is expected to cost $174 million which is the financial responsibility of TransCanada Pipelines Ltd. (Table 9) [16].

The yearly operating costs of the project are estimated at $78.3 million (1980 dollars). The operating costs for the Drake Point Terminal will be an additional $12.2 million and $3.5 million, respectively, (both 1980 dollars) [16].
The primary benefit of the Arctic Pilot Project will be the development of world leadership in a year-round transportation system. The project also holds the promise of many other benefits to Canada which include:

1. The project will generate considerable revenues through the export sale of natural gas over the 20-year operating life.

2. The project will add 450 billion cu m of gas to Canada's gas supply by demonstrating that discovered Arctic gas can be brought to market economically. This increase will help justify a release of Western Canadian gas supplies for export markets.

3. The project will provide positive proof of deliverability, thereby providing a substantial cash flow which will encourage greater exploration.

4. Decreased imports from foreign countries improving the balance of payments.

5. The project will develop Canadian technological expertise in the production and transportation systems for Arctic gas.

6. The project will provide additional education, job and business opportunities, as well as improved transportation and communications systems for northern residents.

7. The project will provide impetus for further development of the substantial resources in the extreme North by proving the viability of a year-round transportation system [1].
F. East Coast

The potential hydrocarbon areas off Labrador, Newfoundland, Nova Scotia, and New Brunswick stretch more than 3,200 km north-south and approximately 1,600 km east-west [19].

The recent oil finds at Hibernia and the gas discovery near Sable Island have renewed industry interest in this high-potential area. Dome estimates probable reserves here of 1.9 billion bbl and an ultimate potential of 7.0 billion bbl, with probable gas reserves of 9.6 tcf and potential reserves of 58.7 tcf [37].

Fig. 6-70 shows the east coast of Canada and the areas of present activity. The Scotian shelf will have fewer production problems because of its proximity in shallow water. The Sable Island region within the Scotian shelf is hoping to prove an estimated 3 trillion cu ft of gas (Fig. 6-71). Petro-Canada’s Chairman Bill Hopper says Sable could be Canada’s first offshore producing area. Over the next two years Petro-Canada and partners will drill two more wells in the Sable Island area and at least one wildcat at an estimated cost of $130 million [57].

Gas fields studied within the Scotian shelf area include Thebaud and Venture. The sea depth in this region was found to vary from 90 m (Thebaud) to 105 m (Venture) while the distance to shore varied from 200 km (Thebaud) to 300 km (Venture). The distance from shore facilities to nearby marketing areas were approximately 50 km for both fields. Flow rates based on reserves and initial flow rate capacities were estimated to be 25 MMCFD for both fields. The average formation depth was reported to be approximately 3380 m [57].
Figure 6-70: Where the action is off Eastern Canada."
Figure 6-71: The Sable Basin area. \(^{57}\)
Scotian Shelf gas fields are located in relatively calm waters (Zone 1) [47] which makes them prime candidates for drilling with a semi-submersible rig or a drillship [47]. Rig, trench, and laying vessel downtime is minimal due to the calm ocean conditions. A dry wellhead installation accompanied with single completion techniques will be primarily used in this area. [47] A complete listing of the parameters used in the economic analysis are outlined in Section VII (Table 15) of this thesis. The capital and operating cost ratios are summarized in Table 16 of Section VII.

The second area of East Coast activity will be the Labrador Shelf, a 1000-km-long sedimentary basin where four gas-condensate discoveries have been made and two more indicated. Severe weather conditions restrict the operation of drillships to approximately 100 days/year (Fig. 6-72). To date, only 20 wells have been drilled in the entire area [22].

Petro-Canada is the operator for the Labrador group and is currently utilizing three drillships [22].

The four confirmed discoveries in the Labrador program are the Gudrid well which tested 20 MMcfd of gas; Bjarni, 12.9 MMcfd; Snorri, 9.8 MMcfd; and Hopedale, 14.3 MMcfd [57].

These wells also produced minor quantities of condensate ranging from 100 b/d to 500 b/d. The Hekja and Roberval K-92 wells are indicated gas discoveries (Fig. 6-70, 73) [57].

Studies of production systems for use off Labrador indicate that types designed for North Sea and other areas would be only partially applicable. Sea conditions similar to the North Sea, combined with the presence of ice pack during half the year and
Figure 6-72: Environmental constraints in the Labrador area.

Figure 6-73: The promising Labrador area.
drifting iceberg conditions throughout the year, demand a unique production system [22].

The exploration acreage lies in water depths of from 100 to 300 m. The average mass of the bergs is about 1 million tons, although bergs weighing 50 million tons have been observed. The larger bergs can scour the seafloor in water depths exceeding 300 m. Average scour depth is about 1 m, with a maximum scour depth of 6 m [19].

Six production concepts were reviewed to determine which warranted further study. These are:

1. A fixed concrete or steel structure (Fig. 6-74)
2. An artificial island or fixed structure on a submerged mount (Fig. 6-75)
3. A caisson platform equipped with an ice-cutting device
4. A multi-phase transportation scheme via pipeline to shore in areas protected from iceberg scour
5. A totally submarine production unit
6. Underground cavities with access by tunnel [22].

The studies indicate that three of the systems considered are practical in the medium (5-10 years) to long (10-25 years) term. These are the artificial island, the floating system, and the multi-phase transportation via pipeline methods [22].

Of all the possible fixed structure ideas, the most feasible alternative appears to be the artificial island concept (Fig. 6-75). Since construction time is excessive for water depths in the 100 to 150 m range, it has been proposed to install a gravity structure located on a submerged mound. Such a concept would suit sites such as Bjarni, Snorri and Rut (Fig. 6-73), where transportation of production could be by pipeline or tanker [22].
Figure 6-74: Fixed gravity platform.22

Figure 6-75: Gravity structure on artificial island.22
This alternative presents three technical problems which remain to be solved. These are: (1) the submerged mound will have to resist iceberg action for the field’s life; (2) the gravity structure will have to resist multi-year ice floes trapped in the pack; and (3) transportation will have to be performed in most cases by tanker (pipeline feasibility is questionable in most areas of the Labrador Shelf).

Liquefaction and gas processing facilities could be set up on the same platform. This alternative is primarily aimed at shallow water prospects [22].

The floating system alternative (Fig. 6-76) would permit year-round production. This proposal would be composed of the following components:

1. A Christmas tree and manifold placed in an excavation sufficiently deep to avoid iceberg scouring,
2. A replaceable flexible flowline that will lie on the seabed,
3. A dynamically positioned production platform (DYPOS PAR) equipped with an ice-cutter capable of maintaining position by disaggregating ice under ice pack conditions,
4. A riser with quick-disconnection capability in case of iceberg occurrence,
5. A shuttle storage DYPOS PAR also equipped with an ice cutter, and
6. Several shuttle tankers designed as icebreakers to offload production from the shuttle DYPOS PAR while drifting together [22].

The shuttle storage DYPOS PAR and shuttle tankers could be replaced by a pipeline to shore when feasible. Studies have
Figure 6-76: Year-round plan for producing oil off Labrador.\textsuperscript{22}
shown this is possible only in water depths of 140 m or more because of the rise and dynamically positioning concept requirement [22].

The remaining attractive plan is the multi-phase transportation of hydrocarbons by pipe line to shore. Components of this system are:

1. Subsea wellheads arranged in clusters, with a main cluster including a manifold,
2. Dual pipe line to shore to provide for line maintenance and safety,
3. An onshore processing plant and tanker terminal to be set up on the Labrador coast,
4. A year-round control and intervention surface vessel capable of shutting down a single well or the entire field when necessary. Repair and major maintenance would be performed during the ice-free season.

Christmas trees, manifold and flowlines have to be placed in an excavation or natural depression to protect them from scour, similar to the floating system. A safety valve system to shut-in wells during an emergency would be necessary. It would be mandatory to control this system from the surface [22].

Labrador environmental conditions will make the design, operation, installation and maintenance of a pipe line differ significantly from one in the North Sea. Some of the important differences involve:

1. The extensive and deep scour of icebergs off Labrador which demand use of deep trenches or natural protection for the pipe line,
2. Crossing of the Labrador marginal trough, and
3. The presence of ice pack for six months of every year [22].

In areas where scouring occurs, the pipe line will have to be buried in a trench at least 7 m deep for protection. This value was obtained from a computer model in which the input was the type of soil likely to be present and 100-year environmental conditions. The maximum value of 6 m agrees with the bottom surveys performed at Leif, Gudrid, Bjarni and Snorri, where extreme scour depths measured range from 5 to 6 m, varying with locations [22].

Pipe line routes exist at some sites (Gilbert and Gudrid) which are naturally protected against scouring until near shore. However, in most places the pipe line will have to be protected by means of trenching. Present methods and trenching equipment for deep water are capable of a depth of only 2 or 3 m. It is doubtful that such depths could be attained with Labrador soil conditions and water depths. Major research and development studies will have to be performed [22].

Because of the presence of icebergs throughout the year, a dynamically positioned lay barge will be required. The pipe line can be constructed only during the ice-free season [22].

There should be no major problems year-round in performing normal maintenance. Major repairs will probably be impossible during the winter season and therefore have to be deferred until the ice-free season [22].

Robert A. Meneley, Petro-Canada's Vice-President for Exploration, estimates production from Labrador basin is not likely until 1990 [37].
Gas fields studies within the Labrador shelf area include Gudrid, Bjarni, Snorri, and Hopedale. The sea depth in this region was found to vary from 85 m (Hopedale) to 100 m (Gudrid) while the distance to shore varied from 130 km (Hopedale) to 160 km (Snorri). Flow rates based on reserves and initial flow rate capacities ranged from 10 (Snorri) to 20 MMCFD (Gudrid). The average formation depth was determined to be about 3100 m [57].

Hibernia has been labeled as a major oil accumulation for the North Atlantic (Fig. 6-77) [57]. The P-15 discovery along with the 0-35 and B-08 appraisal wells indicated the existence of this large field (Fig. 6-78) [33].

The Hibernia field is located 315 km east-southeast of St. John’s harbor. The Hibernia wells lie near the northeast extremity of the Banks within the 100 m water contour (Fig. 6-70). The water bottom is fairly smooth with only minor relief in the vicinity of the structure [57].

Water depths vary from 76 m to 86 m across the structure. The shelf break lies farther east near the 200-m water depth [57].

On the Grand Banks, in the fall to spring period, storms with high winds and increased seas are frequent. From April through June icebergs tend to concentrate along the shelf break at the 200-m water depth [57].

After the testing of the Hibernia B-08 step-out well (Fig. 6-79) which flowed oil at a calculated rate of 21,000 b/d on 1/2-in. choke, the Newfoundland government claimed there is a 50 percent probability that Hibernia contains 1.8 billion bbl of oil
Figure 6-77: Offshore Newfoundland.

Figure 6-78: The Hibernia area offshore Newfoundland.
Figure 6-79: Hibernia area including seismic structure and cross section.43

Figure 6-80: Generalized Hibernia structure.72
plus 1.5 tcf of solution gas and an additional 0.5 tcf of non-associated gas. These estimates place Hibernia in a league with such North Sea giants as Statjord and Brent fields [33].

Fig. 6-80 provides a generalized map of the Hibernia structure which is a large rollover anticline, almost domal shaped in plane view. The structure has a complex series of normal faults and is immediately adjacent to the major basement controlled hinge fault which separates the shelf from the hinge zone. The generalized structural contours are on the Avalon zone which is one of the major potentially productive units. Most of the faults exhibit little growth with the exception of the basement hinge fault. This is shown on the diagrammatic structural cross-section B-B' (Fig. 6-81) which extends from the shelf, across the Hibernia structure, through the first appraisal well O-35, the discovery well P-15, and the second appraisal well B-08 [72].

Fig. 6-82 illustrates the stratigraphy of the Hibernia structure. The positions of the Avalon and Hibernia pay sands within the Lower Cretaceous section are shown, as well as the marked thickening of the Avalon from P-15 to O-35 [72].

Fig. 6-83 summarizes production data on the Hibernia P-15 discovery well. Total net pay of the three zones is about 89 m with average porosities ranging from 10 percent in Jeanne d'Arc to 18 percent in the Avalon and Hibernia zones. The oil flow in barrels per day from the tests is shown along with the choke size and gravity of the oils recovered [72].

Fig. 6-84 shows similar data for the O-35 well. All of the production testing was done on sands in the Avalon zone which is considerably thicker at this location than at P-15 [72]. Net pay
Figure 6-81: Diagrammatic section B-B'.72

Figure 6-82: Hibernia stratigraphy.72

Figure 6-83: Hibernia P-15 production data.72
Figure 6-84: Hibernia 0-35 production data.37

Figure 6-85: A look at new exploration rights off Canada.28
in the Avalon zone at 0-35 is 137 m compared to the 17 m at P-15. The sands in general have good porosities with the average being 21 percent. Flow rates and quality of the crude were also good. The 0-35 well was the first Hibernia step-out located 3 km west of the discovery well and produced at about 20,000 b/d [37].

The fourth appraisal well, K-18 (Fig. 6-79), was tested in five intervals and flowed 18,000 b/d oil and 22.5 MMcfd of gas. This well is located about 4 km northwest of the P-15 discovery well. [6] The tests, in three main geological formations, confirmed productive zones previously found in the discovery well and the two other appraisal wells [19].

The fifth appraisal well, J-34 (Fig. 6-79), is located about 5 km southwest of the P-15 strike. The well had a target depth of 4,270 m and was to be drilled by the Ocean Ranger, billed as the world's largest semisubmersible drilling rig. The Ocean Ranger was drilling at 3,713 m on February 15, 1982 when a raging storm sank the huge semi-submersible in about 80 m of water. This accident claimed the lives of 84 persons, which is the second worst offshore rig accident. History's worst offshore rig accident was in the North Sea on March 27, 1980 when 123 lives were lost [60].

Members of the Hibernia group are: Mobil Canada 28.12 percent, Gulf Canada Resources Inc. and Petro-Canada Exploration Inc. 25 percent each, Chevron Standard Ltd. 16.41 percent, and Columbia Gas Development of Canada Ltd. 5.47 percent. Mobil Canada will be the operator in future production schemes [60].

155
Presently, there exists a dispute between Canada's federal government and Newfoundland over which government holds jurisdiction over offshore resources. This dispute could wind up in the Canadian Supreme Court, causing long delays in development of discoveries by Mobil Canada and other companies [60].

Recently, Canada's Department of Energy, Mines, and Resources awarded oil and gas exploration rights covering six areas south and east of Nova Scotia (Fig. 6-85). The farmout is seen as a result of a federal exploration incentive program that gives preference to Canadian companies [28].
G. West Coast

The present moratorium on British Columbia offshore oil and gas activity has made it difficult to establish the future potential of this region. Figs. 6-86, 87, 88 are maps which show the primary sedimentary basins of interest. There are three main areas of future potential which include: Tofino basin, west of Vancouver Islands; Winona basin, northwest of the island; and the Queen Charlotte Sound-Hecate Strait Dixon Entrance region, north of Vancouver Island [69].

A report by the Geological Survey of Canada says Canada's west coast offshore has limited oil and gas resources [68].

The report estimated an average potential of 9.4 tcf of gas and 241 million bbl of oil but noted this potential would be reduced by the high cost of offshore work [68].

Another report issued by the Department of Energy, Mines, and Resources indicated that the magnitude of the ultimate recoverable reserves in the sediments of Hecate Strait and Queen Charlotte Sound could be as high as those of Cook Inlet in Alaska, about 1 billion bbl of oil and 5 tcf of gas [64].

The Canadian government and the provincial governments of Alberta and British Columbia have agreed to build a terminal on the northern coast of British Columbia to ship petrochemicals to Japan and other Asian markets [62].

The National Harbors Board will build the terminal on Eigher Kain Island or Ridley Island in time to handle petrochemical shipments from Alberta in 1984 [62].

Ridley Island also is the site of a new $200 million coal port and a $260 million grain export terminal [62].
Figure 6-86: Major basins offshore British Columbia.  

Figure 6-87: Index map: Canadian West Coast.
Figure 6-88: Physiographic nomenclature west of British Columbia.69
The West Coast has feasible characteristics for the implementation of the BMMP concept. It is hard to determine the exact feasibility because of the lack of data, due to a moratorium on drilling activity. In the future, if smaller gas fields are discovered, it appears that the BMMP would be a highly practical alternative.
H. Political Climate

Trudeau's Liberal Party has made energy costs and ownership the focal points of its first federal budget enacted since returning to power [24]. The budget's National Energy Policy (NEP) was introduced on October 28, 1980, with strong nationalistic overtones and new federal taxes [20]. It was a shock to several companies, primarily multinational firms with ownership and corporate headquarters outside Canada [24].

The main objective of the NEP, as summarized by the federal Liberal Government in Ottawa, are to:

-- Increase Canadian ownership of the domestic petroleum industry to 50% by 1990, compared with a pre-NEP level of approximately 30 per cent.

-- Achieve oil self-sufficiency by the end of this decade.

-- Increase the federal government's share of petroleum revenues in comparison with the share received by industry and the producing provinces.

-- Stimulate exploration on federal frontier acreage off the East Coast and in the Arctic [20].

The tools used in accomplishing these goals include exploration grants covering up to 80 percent of costs for work on federal land by companies with high levels of Canadian ownership (Tables 10, 11) [50].

Trudeau's plans for changes in oil company ownership are designed to favor companies having a high percentage of Canadian ownership and control. Of the 25 leading oil companies operating
in Canada, 17 are foreign-owned and account for 72% percent of the nation's oil business.

Trudeau believes oil prices are arbitrary and wants to isolate Canada from increases by a schedule adopted by the NEP (Table 12), which has since been changed. Features of Trudeau’s national energy policy are:

1. An 8 percent surtax on net operating revenues
2. A phasing out of the 33.3 percent depletion allowance for exploration in Southern Canada
3. Stringent rules for Arctic and offshore exploration
4. An increase in the price of gas for U.S. export
5. An acquisition program by Petro-Canada designed to give Canada a minimum of 50 percent ownership of the oil business
6. Controlled price rises designed to keep Canada’s oil prices below that of the U.S. and world prices
7. Economic pressures designed to turn ownership and control of Canada’s oil business over to Canadians
8. Mandatory maximum use of Canadian companies and equipment.
9. Rapid development of offshore resources [24].

Some of the measurable results following the installation of the NEP are:

-- A takeover fever as foreign-owned companies either sell their Canadian assets or attempt to increase their Canadian ownership levels to obtain better treatment under the NEP [20].
Petroleum incentives under the National Energy Program

(As a percent of allowable expenditures)

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Table 10: Petroleum Incentives Under the National Energy Program (NEP).

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<td></td>
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Table 11: Depletion Allowances and Incentive Payments for Oil and Gas Exploration and Development.
A migration of rigs and dollars to the U.S. and elsewhere by many smaller companies seeking higher returns. After climbing to a record level of 455.6 in August 1980, the average number of active rotary rigs slumped to 230.4 in August 1981 (Figure 6-89) [20].

Substantially higher energy prices for Canadian consumers to pay for acquisitions of foreign companies by state-owned Petro-Canada.

A rising bill for oil imports

A decline in exploration/development in the producing provinces. The decline followed a year in which a record 9,070 wells were completed.

Reduced cash flow of about 25-30 percent for many companies, resulting in a trimming of corporate budgets and capital spending.

Postponement of several costly heavy oil and tertiary recovery projects in Alberta [20].

In response to the original NEP, Alberta imposed a phased cut of 180,000 b/d in its oil production and refused to grant approval for two large oil sands projects with a total price tag of about $24 billion. NEP had envisioned a rising level of oil sands production to take up the slack as conventional output declined [20].

The most dramatic effect of the NEP has been the increase of takeovers and rumors of takeovers involving big names in the Canadian industry such as Dome Petroleum Ltd., Nova Corporation, and Petro-Canada [78].
How Canadian Oil is Priced

Canadian pricing of oil at the wellhead is caught between the federal government’s attempt to hold down the price of oil ultimately paid by consumers, and the oil industry’s need to cover costs and make a profit.

Until recently, the wellhead price was between $14 and $15. Sagging exploration and development caused government to raise the price permitted to $16.75 last year and set up a complicated pricing plan (which oil operators claim will not encourage the exploration and development work necessary).

Here is Trudeau’s pricing policy, as contained in the National Energy Policy portion of the Federal Budget:

The wellhead price increased Jan. 1 by $1/bbl, and will increase each six months by an additional $1/bbl through the end of 1983. Beginning in 1984, the wellhead price will increase each six months by $2.25/bbl through the end of 1985. Beginning in 1986, the price per barrel will rise by $3.50/bbl, until it achieves parity either with the price permitted for Canadian tar sand production, or 85 percent of the imported oil price or U.S. oil price, whichever is smaller.

Proposed Rise in Oil Wellhead Price under National Energy Proposal:

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<th>Conventional Oil</th>
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<td>$38.75</td>
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Table 12: Initial Proposed Rise in Oil Wellhead Price under the NEP.

Figure 6-80: How Canadian Drilling Has Risen and Fallen.
On the foreign-owned target list were Conoco Inc., Hudson’s Bay Oil and Gas Limited, Aquitaine Company of Canada, Ltd., Petrofina Canada, Limited, Marathon Petroleum Canada, Limited, and others in the small and medium size range [78].

The national oil company, Petro-Canada, which had already acquired foreign-controlled Pacific Petroleum, Ltd. and Atlantic Richfield Canada, Ltd. in pre-NEP days, quickly set its sights on acquisition of Belgian-controlled Petrofina Canada shortly after the NEP was announced [50].

In February 1981, Petro-Canada acquired Petrofina Canada by paying $1.46 billion or $120/share for shares which were trading on the market prior to the takeover for about $60/share [50].

Most of the cost of the acquisition will be financed from a special Canadian ownership account set up under the NEP which can add up to $4/bbl to finance acquisitions. Canadians will pay 85% of the cost of acquiring Petrofina at gasoline pumps [50].

The most spectacular acquisition to date was the bitterly contested takeover by Dome of controlling interest in Hudson’s Bay from Conoco in June 1981. Dome acquired 52.9 percent of Hudson’s Bay for $1.96 billion [50].

A primary objective of the takeovers has been to increase Canadian ownership levels of the buyers and to gain control of important offshore land positions. But the trend has resulted in the federal government’s political objective of increased Canadianization [20].

More than 100 Canadian oil companies have set up subsidiaries or taken farmouts on acreage in the U.S., with a concentration in the Rocky Mountain states [20].
The Canadian Association of Geophysical Contractors reports that there has been a $30 million dip in industry revenues and a loss of about 1,000 jobs [20].

Since the introduction of the NEP, about 140 drilling rigs, and 72 service rigs have left Canada, headed mainly for the U.S. [20]. The assessment of the original NEP and reaction to it by Canadian Hunter Exploration, Ltd., a Calgary independent, is typical of scores of similar companies. Jim Gray, Hunter Executive Vice-President said, "After all pending deals and after Petro-Canada's 25% back-in on all present leases, I calculate that our ambitious state exploration company will control about 130 million net acres in Canada's frontiers.

"No company can effectively explore 130 million net exploration acres, and this gift to Petro-Canada will result in stagnation in our frontiers [78].

Figure 6-90 shows the "split" of a barrel from an Alberta field and one from Hibernia under federal and provincial ownership. Provincial ownership would bring benefits that could make Newfoundland/Labrador self-sufficient and eliminate its role as a perennial welfare recipient [24].

If the federal government controls the province's offshore, Newfoundland/Labrador's only source of oil revenue will be royalties collected by the federal government. Figure 6-91 shows the money split on gross revenue, net revenue and total government revenue under federal and provincial control, assuming 1 billion
Figure 6-90: Barrel Split from Alberta Oilfield (A) and from Hibernia Under Federal Ownership (B) and Provincial Ownership (C). 24

Figure 6-91: Revenue Split from Hibernia Production

REVENUE SPLIT from 1-billion-bbl Hibernia production between federal and provincial governments (A), total net revenue split (B) and total gross revenue split (C). Assumes 8 percent discount, Canadian prices per federal budget, 8 percent Petroleum and Gas Revenue Tax, and Petro-Canada participation of 43.75 percent.
bbl production, an 8 percent discount, Canadian prices per the federal budget, and a 43.75 percent participation by Petro-Canada [24].

On September 1, 1981, Ottawa and Alberta signed an agreement on energy pricing and revenue sharing, ending a lengthy stalemate on the issues. The agreement extends over a five year period until mid-1986 [20].

The primary element of the agreement is a two tier price system which will raise the price of old oil to a maximum of 75 percent of the world price and increase the price of new and synthetic oil close to world levels in 1982 [20].

Price for existing oil production will increase $4.50/bbl in 1982, and $8/yr/bbl during 1983-1986, raising wellhead prices to $57.75 from the current $21.25. But, Ottawa said, the price will never exceed 75% of the world price. [20]

The price of natural gas will increase by $0.50/Mcf/year in increments of $0.25 every six months beginning February 1, 1982 [20].

Alberta will move immediately to reverse the effect of three cuts in its oil production totaling 180,000 b/d. The cuts started in March, 1981 in three stages of 60,000 b/d each in retaliation against federal policies [20].

Federal Energy Minister Marc Lalonde, said the agreement will produce $32 billion in additional revenues, compared with previous price and tax levels under the original national energy program (NEP). Of the added revenues, Ottawa will collect $15 billion, Alberta $9 billion, and industry $10 billion [20].
In 1981, Canadian oil and gas prices rose 24 percent while world petroleum prices have fallen. At the same time, high taxes and constraints on multinationals have resulted in a collapse of oil exploration in western Canada. The future of one of the brighter projects, the $12 billion Alsands consortium to mine Alberta tar sands, has turned sour because of pullouts by major producers including Amoco Petroleum Canada, Chevron Standard, and Shell Explorer. "The government has killed the golden goose of the Canadian petroleum industry," says Clem W. Dumett, Jr., Chairman of the Canadian Petroleum Association [41].
A computer program written by Kulachol [49] and reprogrammed by Albert Chu was used in this incremental economic analysis. Kulachol's program was modified by Chu in order to include the extra distance to marketing facilities. The following assumptions were used in determining input parameters for the computer program (Tables 13 and 14).

1. Flow rate, capacities, except where known, were calculated by dividing the known or approximated recoverable reserves into constant, daily flow rates, assuming a 25-year field life.

2. Weather related downtime values for drilling, pipeline laying, and trenching were estimated by the author considering the location of that particular gas field. Any error resulting from this approximation should be negligible.

3. Distances from the actual gas field to the closest marketing facility (i.e., Perth, Sydney) were estimated by the author.

4. The author selected the type of drilling rig, subsea equipment, pipe-laying, and trenching vessels according to the type of environment, flow capacity, distance to shore, and sea depth.

* The computer program and specific details regarding its use are located in an Appendix of this thesis.
Table 13

AUSTRALIA

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<th>Region and Field Names</th>
<th>Sea Depth (ft)</th>
<th>Distance to Shore (mi)</th>
<th>Flow Rate (MMSCF/D)</th>
<th>Formation Depth (ft)</th>
<th>Zone</th>
<th>Rig Type</th>
<th>Rig Down Time (Z)</th>
<th>Wet or Dry (O=D)</th>
<th>Single or Multi (O=S)</th>
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*Note: 25 MMSCF/D is assumed value
### Table 14

**Canada**

**Actual Data**

**Input Parameters**

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Table 15

METHANOL ALTERNATIVE TO CONVENTIONAL METHOD RATIOS

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<th>Yearly Cost</th>
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<tr>
<td>Flounder</td>
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<td>1.38</td>
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<td>Turrun</td>
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<td>2.45</td>
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<td>Sole</td>
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<td>1.32</td>
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<td>Bream</td>
<td>2.11</td>
<td>2.49</td>
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<td>IV. Tasmania, Australia</td>
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<tr>
<td>Pelican</td>
<td>1.56</td>
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<tr>
<td>Thebaud</td>
<td>1.10</td>
<td>1.41</td>
</tr>
<tr>
<td>Venture</td>
<td>0.96</td>
<td>1.29</td>
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<tr>
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<tr>
<td>Gudrid</td>
<td>1.38</td>
<td>2.26</td>
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<td>Bjarni</td>
<td>2.59</td>
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<td>Snorri</td>
<td>3.10</td>
<td>2.91</td>
</tr>
<tr>
<td>Hopedale</td>
<td>3.41</td>
<td>2.96</td>
</tr>
<tr>
<td>VII. Hibernia, Canada</td>
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<td></td>
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<tr>
<td>Hibernia</td>
<td>1.12</td>
<td>1.24</td>
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VIII. CONCLUSIONS AND RECOMMENDATIONS

An economic analysis comparing the BMMP with conventional platform techniques was performed on 17 known Australian gas fields producing from 25-230 MMSCFD, lying 20-300 km offshore in water depths ranging from 45-250 m. The primary purpose of the computer analysis was to calculate capital cost and yearly O & M operation and maintenance cost ratios for two alternate methods of development, i.e. BMMP vs. conventional.

The seventeen fields considered were divided into four geographic regions: Victoria, Tasmania, Western Australia, and the Northern Territory. The fields located in the Victoria and Tasmania regions were found to be unfavorable for the BMMP primarily because of their shallower sea depths, short distances to shore, and proximity to marketing facilities (Table 15). The fields located in the Western Australia and Northern Territory regions yielded favorable results for the BMMP due primarily to their marginal status and remote locations.

The Gorgon field located in the Western Australia region yielded the most favorable results for the use of the BMMP. Gorgon's capital cost and yearly O & M ratios were calculated to be 0.51 and 0.46, respectively.

The Sunrise and Troubadour fields located within the Northern Territory region also had positive results for BMMP application. Both fields had capital cost ratios which were less than one but only the Sunrise field had a yearly O & M ratio less than one.

An economic analysis comparing the BMMP with conventional platform techniques was performed on seven known East Coast
Canadian gas fields with estimated productive capabilities from 25-125 MMSCFD, lying 100-320 km offshore and in water depths ranging from 80-110 m. Marketing facilities for these candidates ranged from 30-250 km from the fields. The primary purpose of the computer analysis was to calculate capital cost and yearly O & M cost ratios as has been done by Kulachol [47].

The seven fields considered were divided into three geographic regions: Scotian Shelf, Labrador Shelf, and the Hibernia area. The fields located on the Labrador shelf were found to be marginal because of their flow rates and hazardous location in the Arctic area.

The Thebaud and Venture fields located offshore Nova Scotia yielded favorable results for BMMP application. Venture’s capital cost and yearly O & M ratios were calculated to be 0.96 and 1.29, respectively. The Thebaud field yielded results which were very close to break-even with the conventional platform alternatives.

The Hibernia field had capital cost and yearly O & M ratios of 1.12 and 1.24, respectively. These figures are close enough to unity to suggest that the application of the BMMP may be feasible in the near future with an increase in methanol prices.

Onshore, the BMMP looks promising in the Beaufort Sea and Arctic Isles areas. The Beaufort-Alberta O/M dispersion proposal will transport both oil and methanol in a single carrier as opposed to two separate carriers. The economics of this proposal indicate that the O/M dispersion system will cost only about 60% of the cost of separate carriers and result in an initial capital
investment saving of about $22 billion. Annual operating expenses are approximately the same when compared with a two carrier system.

The BMMP can also be applied in the severe environmental conditions of the Arctic Isles. There are enough proven gas reserves in the Arctic region to justify both LNG and BMMP projects. Tankers similar to those used in the Arctic Pilot Project can be used to transport MeOH to markets in Eastern Canada and/or Europe.

The Canadian West Coast also has feasible characteristics for the implementation of the BMMP concept. It is difficult to determine this feasibility due to the scarcity of data resulting from the current moratorium on offshore British Columbia drilling. In the future, if smaller gas fields are discovered it appears that the BMMP would be a highly practical alternative.

Overall, it is quite evident from this study that the BMMP process is a financially attractive means of producing and transporting natural gas and methanol products in Australia and Canada. The financial benefits associated with the BMMP should indicate that the future use of the BMMP is warranted in both Australia and Canada.
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X. APPENDIX: ECONOMICS COMPUTER PROGRAM

```
program barge (input, output, terminout, term in, ratiofyle, AlternativeCap, 
AltYear, ConvCap, ConvYear);
(*Programmer: Ori Kopelman 
Account name: e:exit   Filename: Barge.pgo 
Date of completion: May 30, 1981

Done as a research project for Professor Marsden in Petroleum Engineering, while enrolled in P.E. 173, for 3 units of credit.

This program can be run either with terminal-user interaction (for input) or from an input file. File input should be designated either as tty; for terminal input, or the name of some input file. The file output should always be some output file to which the data results will always be sent. The file terminout must be used for terminal interaction by responding with termout/tty; and also term in must be designated terminin/tty.

Here is the format to be used for inputting data from an input file:

Each problem (field) should be inputted in one line of the file, in the following order:

1. Program description? (y for yes, n for no)
2. Zone (a for cala, b for north sea, c for arctic)
3. Type of wellhead (d for dry, w for wet)
4. Type of well (s for single, m for multiple)
5. Trenching used? (y for yes, n for no)
6. Drilltype(use 0,1,2,3, or 4)—see description below
7. Drilling Depth (real value—nnn.d)
8. Sea Depth (real value)
9. Downtime (real value)
10. Well flow capacity (real value)
11. Average plant on stream time, in % (real value)
12. Distance from field to shore in feet (real value)
13. Type of pipe-laying vessel use (0, 1, 2, or 3), for small barge, large barge, small semi-submersible (ss)
14. Downtime of pipe-laying vessel used, in %. (real value).
15. Downtime of trench laying vessel, in % (real value).

If trenching is not used, enter 0.0

var help, (*checks if you want a program description*)
          rerun, (*asks if he wants a rerun*)
WellHead, (*wet or dry (w or d)*)
Fyle, (*checks if file used for input (y for yes, n for no)*)
Well, (*single or multiple well (s or m)*)
Trenching, (*y for yes if used, n for no if not used) 
zone(cale, north sea, or arctic): char
Drilltype, (*Jackup, semisubmersible, dynamically positioned*)
PipeLayVessel, (*0 for small barge, 1 for large barge: 
2 for small semi-submersible or ship, and 
3 for large semi-submersible or ship.*)
Count, (*keeps count of how many fields were in the data set)
NumKells, (*number of wells*): integer
```

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Procedure Description:

(*This procedure gives the user a description of the program if he asks for it*)

begin (*description*)

write(termin, 'Would you like to see a program description? 1');
write(termin, 'Type y for yes, n for no. ');;
break(termin);
readln(termin);
read(termin, help);
if help='y' then begin
    writeln(termin, 'This program computes the capital costs and');
end;}
writeln(termout, 'production of methanol from offshore');
writeln(termout, natural gas resources (in the form of associated ());
writeln(termout, natural gas resources (in the form of associated ());
writeln(termout, gas production (through use of a platform));
writeln(termout, for all offshore areas of the world. For ());
writeln(termout, convenience, the areas have been divided into ());
writeln(termout, zone a: relatively calm areas ());
writeln(termout, zone b: the north sea ());
writeln(termout, zone c: the arctic area ());
writeln(termout, 'The equations used here have been established in ());
writeln(termout, five of ());
writeln(termout, );
writeln(termout, );
writeln(termout, );
writeln(termout, This program can be run either with terminal- (for input) or from an input file. File input (designated either as tty: for terminal input, input file. The file Output should always be which the data results will always be sent. must be used for terminal interaction by resp (termout, tty: and also term must be design-));
writeln(termout, );
writeln(termout, Here is the format to be used for inputting (for input) or from an input file. File input in the following order: ());
writeln(termout, 1. Program description? (y for yes, or n) ());
writeln(termout, 2. Zone (a for calm, b for North sea, c for ());
writeln(termout, 3. Type of wellhead (d for dry, w for wet ());
writeln(termout, 4. Type of well (s for single, m for multiple ());
writeln(termout, 4a. Trenching used? (y for yes, n for no) ());
writeln(termout, 5. If you want a return or not (y for n) ());
writeln(termout, This should only be used for last line of file) ());
writeln(termout, 6. Drilltype (use 0, 1.2.3, or 4) —see description ());
writeln(termout, 7. Drilling Depth (real value) ());
writeln(termout, 8. Sea Depth (real value) ());
writeln(termout, 9. Downtime (real value) ());
writeln(termout, 10. Well flow capacity (real value) ());
writeln(termout, 11. Average plant on stream time, in ());
writeln(termout, 12. Distance from field to shore in feet (real ());
writeln(termout, 13. Type of pipe-laying vessel use (0.1.2, or ());
writeln(termout, small barge, large barge, small semi- ());
writeln(termout, 14. Downtime of pipe-laying vessel used, in ());
writeln(termout, 15. Downtime of trench laying vessel, in ());
writeln(termout, 'If trenching is not used, enter 0.0) ());

end; (*of program description*)
end; (*Description*)

Procedure Import:
(*This procedure inputs all the necessary data*)
begin (*input*)
If fyle='y' then:
begin
while not eoln do
read(help:zc::wellhead, well, trenching, rerun);
read(drilltype, depth, time, flow, PlantOnTime);
read(SendDistance, PipeLayVessel, LayVesDT, TVDT);

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repeat ("Loop assures that input is only a, b, or c")
write(termout, "What zone? Type a for calm, b for North Sea, c for arctic.");
break(termout);
read(termin);
read(termin, zone);
until (zone='a') or (zone='b') or (zone='c');
writeln;
repeat ("Loop assures proper input")
write(termout, "From what are you drilling? Type 0 for Jackup (not)");
write(termout, "to be used in zone c.");
write(termout, "1 for semi-submersible, 2 for Dynamically Positioned ");
write(termout, "3 for drillship, and 4 for DP Drillship.");
break(termout);
read(termin);
read(termin, drilltype);
until (drilltype=0) or (drilltype=1) or (drilltype=3) or (drilltype=4)
or (drilltype=2);
writeln;
write(termout, "To what depth are you drilling (in feet, real value)? ");
read(termin, depth);
write(termout, "What is the sea depth? (real value please) ");
read(termin, SeaDepth);
write(termout, "What % downtime? (real value please) ");
read(termin, DownTime);
write(termout, "What is the well's flow capacity in MMcf/d? (real value) ");
break(termout);
read(termin, plant);
write(termout, "What kind pipe-laying vessel are you using? ");
break(termout);
read(termin, WellHead);
until (WellHead='u') or (WellHead='d');
write(termout, "Type s for single or m for multiple wells");
break(termout);
read(termin, Well);
write(termout, "What is the plant on stream time (in %)?");
break(termout);
read(termin, PlantOnTime);
write(termout, "What kind of pipe-laying vessel are you using? ");
break(termout);
read(termin, PlantOnTime);
procedure DrillCosts;
(*Computes the drilling cost, after determining number of wells from flow capacity (15 MCFd per well).*)
begin(*drillcosts*)
  NumWells = trunc(flow/15)+1; (*number of wells*)
  frac = 0.938-2.831e-4*Depth+3.512e-8*Depth^2
       -6.49e-13*Depth^3+Depth
       (*fraction of time used in drilling to actual depth.*)
       (*compared with 10,000 feet.*)
  if SeaDepth<100 then
    SeaDepth=100; (*in eqn. s. cost same for <100ft as for 100ft*)
    (*factor is a cost adjustment factor depending on zone and*)
    (*drilltype, from table 9-4, p. 121.*)
  if zone='a' then (*check drilltype if in zone a*)
    begin
      if drilltype=0 then factor=1.4;
      if drilltype=1 then factor=1.0;
      if drilltype=2 then factor=0.8;
      if drilltype=3 then factor=0.98;
      if drilltype=4 then factor=0.99
      Drill1 = 4.91+2.409e-3*(SeaDepth-100); (*table 9-6, p. 121*)
    end;
    if zone='b' then (*check drilltype if in zone b*)
      begin
        if drilltype=0 then factor=1.07;
        if drilltype=1 then factor=1.08;
        if drilltype=2 then factor=1.09;
        if drilltype=3 then factor=1.1;
        if drilltype=4 then factor=1.11
      end;
    end;
  end;
end;(*terminal*)
```plaintext
if drilltype=1 then factor = 1.0;
if drilltype=2 then factor = 3.89;
if drilltype=3 then factor = 0.85;
if drilltype=4 then factor = 3.56;
Drill: = 7.871 + 3.848e-3*(SeaDepth - 100); (*table 5-6, p. 121*)
end;
if zone='c' then (*check drilltype if in zone c*)
begin
if drilltype=0 then:
begin
 writeln(termout,'you used a jackup in zone c, it is illegal.');
 writeln(termout,'Program will assume you meant semisub.');
 break(termout);
 factor = 1.0;
end;
if drilltype=1 then factor = 1.00;
if drilltype=2 then factor = 3.57;
if drilltype=3 then factor = 0.86;
if drilltype=4 then factor = 3.26;
Drill: = 22.03 + 1.06e-3*(SeaDepth - 100); (*table 5-6, p. 121*)
end;
DrillCosts *=factor*Drill1+fact3*Drill1+(1.01+(DownTime-6.4))*NumWells;
end;(*drillcosts*)

Procedure Subsea:
(*This procedure computes the total subsea equipment costs These include well completion costs, manifold costs, and flow line costs.*)

Procedure WellComp;(*Calculates subsea well completion costs*)
var si:real;(*intermediate cost figure*)
begin(*wellcomp*)
if SeaDepth<100 then
SeaDepth := 100;
if Zone='a' then:
begin
if WellHead='w' then
begin
if (SeaDepth>100) and (SeaDepth<400) then
  si := 0.575 - 7.775e-3*SeaDepth + 3.705e-3*SeaDepth*SeaDepth
    - 6.126e-6*SeaDepth + 3.976e-9*SeaDepth^2
else
  si := 0.172 + 2.075e-4*(SeaDepth - 400);
end;
if WellHead='d' then:
begin
if (SeaDepth>100) and (SeaDepth<250) then
  si := 0.718 + 1.90e-3*SeaDepth;
else
  si := 0.279 + 1.51e-3*SeaDepth
end;
if Zone='e' then:
begin
if WellHead='w' then:
begin
if (SeaDepth>100) and (SeaDepth<400) then
  si := 0.735 - 7.413e-3*SeaDepth + 4.779e-3*SeaDepth*SeaDepth
    - 3.906e-6*SeaDepth^2
  else
    si := 0.735 - 7.413e-3*SeaDepth + 4.779e-3*SeaDepth*SeaDepth
  end;
end;
end;(*zone e*)
if zone='b' then:
begin
if WellHead='w' then
begin
if (SeaDepth>100) and (SeaDepth<400) then
  si := 0.735 - 7.413e-3*SeaDepth + 4.779e-3*SeaDepth*SeaDepth
    - 3.906e-6*SeaDepth^2
else
  si := 0.735 - 7.413e-3*SeaDepth + 4.779e-3*SeaDepth*SeaDepth
end;
end;
```

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(*zone fc*)

If zone = 'c' then
  begin
    (*zone c*)
    if WellHead = 'd' then
      begin
        (*zone d*)
        if (SeaDepth > 100) and (SeaDepth < 230) then
          sl = 0.926 + 0.973e-3 * SeaDepth
        else
          sl = 4.86 - 2.34e-4 * SeaDepth
      end;
      if (SeaDepth > 290) and (SeaDepth < 400) then
        sl = 0.926 - 2.374e-3 * SeaDepth
      else
        sl = 4.86 - 3.24e-4 * (SeaDepth - 400);
    end;
    end; (*zone d*)
  end; (*zone c*)

if zone = 'c' then
  begin
    (*zone c*)
    if WellHead = 'w' then
      begin
        (*zone w*)
        if (SeaDepth > 100) and (SeaDepth < 230) then
          sl = 0.926 + 0.973e-3 * SeaDepth
        else
          sl = 4.86 - 2.34e-4 * SeaDepth
      end;
      if (SeaDepth > 290) and (SeaDepth < 400) then
        sl = 0.926 - 2.374e-3 * SeaDepth
      else
        sl = 4.86 - 3.24e-4 * (SeaDepth - 400);
    end;
    end; (*zone w*)

(*)

Cor.pCosts = sl * NumWells; (*Total well completion cost*)

Manifold:
  (*Computes the total Manifold costs*)
  var al: (*Depth sensitivity index for installation cost*)
  SeaDepth: (*Dummy variable to represent SeaDepth*)
  a2: real; (*Depth sensitivity index for hardware costs*)
  RemWells: (*# of wells not included in the 5 well Manifolds*)
  Diff: integer; (*The difference between 5 and RemWells*)

  begin
    NumMani = Trunc(NumWells/9)+1;
    (*Computes # of Manifolds required, which is identical to
      the total # of barges. Each barge can handle up to
      79 tracts, which is equivalent to 9 wells*)
    RemWells = NumWells - (NumMani - 1) * 9;
    (*Remaining number of wells not included in cost of the
     5 well Manifolds, which require additional parts of
     a Manifold, and cost extra*)
    NumBarges = NumMani;
    if RemWells = 1 then
      RemWells = 2; (*Cost is same for 1 or 2 remaining wells*)

Procedure: Manifold;
  (*Computes the total Manifold costs*)
  var al: (*Depth sensitivity index for installation cost*)
  SeaDepth: (*Dummy variable to represent SeaDepth*)
  a2: real; (*Depth sensitivity index for hardware costs*)
  RemWells: (*# of wells not included in the 5 well Manifolds*)
  Diff: integer; (*The difference between 5 and RemWells*)

  begin (*Manifold*)
    NumMani = Trunc(NumWells/9)+1;
    (*Computes # of Manifolds required, which is identical to
      the total # of barges. Each barge can handle up to
      79 tracts, which is equivalent to 9 wells*)
    RemWells = NumWells - (NumMani - 1) * 9;
    (*Remaining number of wells not included in cost of the
     5 well Manifolds, which require additional parts of
     a Manifold, and cost extra*)
    NumBarges = NumMani;
    if RemWells = 1 then
      RemWells = 2; (*Cost is same for 1 or 2 remaining wells*)

end; (*Manifold*)
If diff=0 then
    RemWells = 0. (*That is, another whole Manifold is required*)
else
    if SeaDepth<400 then
        SeeDepth = 400 (*costs remain same for <400 ft as for 400 ft*)
    else
        SeeDepth = SeaDepth;
    a1 := -0.1627.7835e-3*SeeDepth+1.756-6*SeeDepth+SeaDepth
    a2 := -0.2815.756-3*SeeDepth-7.412e-7*SeeDepth+SeeDepth
    +1.3e-10*SeeDepth+SeeDepth+SeeDepth; (*eq. 131*)
    if (WellHead='d') and (Wells='s') then
        Begin (*dry wellhead, single wells*)
        If Zone='a' then
            ManiCosts := (NumMani-1)*0.637*a1+3.543*a2
        (*This line adds the cost of all the Manifolds
         by multiplying the number of Manifolds by the
         cost per Manifold given in the next line, where
         the number of remaining wells is 5, since it's one
         whole Manifold*)
            +0.637*a1+(1.182+0.521*(RemWells-2))*a2.
        (*this adds to the costs the cost of putting
         parts of a Manifold on the remaining number
         of wells*)
        else (*This two part breakdown of costs holds throughout
         the entire procedure*)
        If Zone='b' then
            ManiCosts := (NumMani-1)*0.905*a1+4.995*a2
            +0.905*a1+(2,814+0.727*(RemWells-2))*a2;
        IF Zone='c' then
            ManiCosts := (NumMani-1)*1.326*a1+7.318*a2
            +1.326*a1+(4.173+1.695*(RemWells-2))*a2;
        end (*dry, single wells*)
        if (WellHead='d') and (Wells='s') then
            Begin (*dry, multiple wells*)
        If Zone='a' then
            ManiCosts := (NumMani-1)*0.905*a1+4.466*a2
            +0.905*a1+(3.089+0.787*(RemWells-2))*a2;
        IF Zone='b' then
            ManiCosts := (NumMani-1)*1.357*a1+7.352*a2
            +1.357*a1+(4.341+1.118*(RemWells-2))*a2;
        IF Zone='c' then
            ManiCosts := (NumMani-1)*1.968*a1+11.331*a2
            +1.968*a1+(6.417+1.639*(RemWells-2))*a2;
        end (*dry, multiple*)
        if (WellHead='c') and (Wells='s') then
            Begin (*wet wellheads, single wells*)
        If Zone='a' then
            ManiCosts := (NumMani-1)*0.637*a1+2.089*a2
            +0.637*a1+(0.735+0.451*(RemWells-2))*a2;
        IF Zone='b' then
            ManiCosts := (NumMani-1)*0.905*a1+2.967*a2
            +0.905*a1+(1.014+0.611*(RemWells-2))*a2;
        IF Zone='c' then
            ManiCosts := (NumMani-1)*1.326*a1+4.346*a2
            +1.326*a1+(1.529+0.939*(RemWells-2))*a2;
        end (*wet, single*)
        if (WellHead='c') and (Wells='s') then
            Begin (*wet wellhead, multiple wells*)
        If Zone='a' then
            ManiCosts := (NumMani-1)*0.905*a1+4.014*a2
            +0.905*a1+(1.839+0.723*(RemWells-2))*a2;
        IF Zone='b' then
            ManiCosts := (NumMani-1)*1.357*a1+5.695*a2
            +1.357*a1+(2.611+1.039*(RemWells-2))*a2;
        IF Zone='c' then
            ManiCosts := (NumMani-1)*1.968*a1+11.346*a2
            +1.968*a1+(6.417+1.639*(RemWells-2))*a2;
        end (*wet, multiple*)
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Procedure FlowLine;
(*This procedure computes the cost of flow lines, p. 135*)
var DistWtoM,
DistMtoS:real;
begin (*FlowLine*)
if Well-'s' then
DistWtoM:=3000*NurWells
(*assumption made that the distance from a satellite well to the manifold is 3000 feet.*)
else (*If have multiple wells*)
DistWtoM:=0;
DistMtoS:=1.5*SeaDepth*NurMani;
(*Here follows computation of total flow line costs*)
if Zone='a' then
FlcLnCost:=DistWtoM+0.07e-4+DistMtoS+2.68e-4;
if Zone='b' then
FlcLnCost:=DistWtoM+1.40e-4+DistMtoS+3.58e-4;
if Zone='c' then
FlcLnCost:=DistWtoM+2e-4+DistMtoS+8.0e-4;
end; (*FlowLine*)

begin (*Subsea*)
WellComp;
ManfComp;
FloLnCost;
SubseaCosts:=CompCosts+ManfCosts+FlcLnCost;
(*The total subsea cost is the sum of well completion costs,
total manifold costs, and total flow line costs*)
end. (*Subsea*)

Procedure SubseaCM;
(*This procedure computes the annual subsea equipment operating
and maintenance costs*)
var fac:real; (*factor used in calculating O&M costs*)
begin (*SubseaCM*)
if Zone='a' then
begin (*Zone 'a*)
if (WellHead='U') and (Well='s') then
begin (*Wet, single*)
if SeaDepth<1800 then fac:=0.0944;
if SeaDepth<900 then fac:=0.0714;
if SeaDepth<300 then fac:=0.0326;
if SeaDepth<600 then fac:=0.0474;
end; (*Wet, single*)
if (WellHead='U') and (Well='m') then
begin (*Wet, multiple*)
if SeaDepth<1800 then fac:=0.0472;
end; (*Wet, multiple*)
end.
if $\text{SeaDepth} < 1800$ then $\text{fac} := 0.0805$;
if $\text{SeaDepth} < 1200$ then $\text{fac} := 0.0715$;
if $\text{SeaDepth} < 600$ then $\text{fac} := 0.0633$;
if $\text{SeaDepth} < 400$ then $\text{fac} := 0.0555$;
if $\text{SeaDepth} < 300$ then $\text{fac} := 0.0453$;
end; (* wet, multiple, c+ *)
if (\text{WellHead} = 'd') and (\text{Well} = 's') then
begin (* dry, single, c+ *)
if $\text{SeaDepth} < 1800$ then $\text{fac} := 0.0933$;
if $\text{SeaDepth} < 1200$ then $\text{fac} := 0.0860$;
if $\text{SeaDepth} < 600$ then $\text{fac} := 0.0770$;
end; (* dry, single, c+ *)
if (\text{WellHead} = 'd') and (\text{Well} = 'm') then
begin (* dry, multiple, c+ *)
if $\text{SeaDepth} < 1800$ then $\text{fac} := 0.0469$;
if $\text{SeaDepth} < 1200$ then $\text{fac} := 0.0400$;
if $\text{SeaDepth} < 600$ then $\text{fac} := 0.0335$;
end; (* dry, multiple, c+ *)
if \text{WellHead} = 'w' then
\text{SSCMCosts} := fac*(\text{NumWells}+\text{NumMani})+0.03*\text{SubseaCosts}
(* p. 138-140 in thesis *)
else (* dry+ *)
\text{SSCMCosts} := fac*(\text{NumWells}+\text{NumMani})+0.015*\text{SubseaCosts};
end; (* Subsea01 *)
Procedure BargeCosts;

(*This procedure computes the price of a barge, and its yearly operating costs*)

begin (*BargeCosts*)

PlantCap = PlantCap; (*flow is the field's flow capacity in MMcfd*)

BargeCap = PlantCap; (*Barge capacity of methanol*)

BargePrice = 1.129e-2 * PlantCap; (*price of one barge*)

BargeCMCosts = 0.02 * BargePrice; (*yearly oper. and mainten. costs*)

end; (*BargeCosts*)

Procedure BargeMoor;

(*This procedure computes the cost of the mooring system used for the barges, either SALM or Dynamic positioning system (DPS). In zone a and b the former is used for sea depths under 600 feet, and the latter for all other depths. Also computes the yearly operating and maintenance costs for the mooring system used.*)

var SALMcosts, (*Total cost per SALM unit*)

HpThrust, (*Horse power required by the thrusters*)

HpProp, (*Horse power required by the propellers*)

CostPerHp, (*Cost per horse power required*)

ThrustInst, (*Installation costs for thrusters*)

PropInst, (*Installation costs for propellers*)

DPCosts, (*Control costs for the DPS*)

begin (*BargeMoor*)

if SeaDepth < 100 then SeaDepth = 100; (*costs same for 100 ft.*)

if (SeaDepth <= 600) and (zone < 'c') then

begin (*SALM*)

if zone < 'a' then

SALMcosts = 1.392 + 0.0219 * SeaDepth + 2.893e-9 * SeaDepth * SeaDepth;

if zone < 'b' then

SALMcosts = 3.450 + 0.549 * SeaDepth + 7.143e-9 * SeaDepth * SeaDepth;

SALMcosts = SALMcosts + NumBarges; (*Total SALM costs*)

SALMcosts = 0.005 * SALMcosts;

MooringCosts = 5 * SALMcosts;

end (*SALM*)

else

begin (*DPS*)

HpThrust = BargeCap * 0.675;

HpProp = BargeCap * 0.225;

CostPerHp = 3.9e-4;

ThrustInst = 4.24;

PropInst = 0.53;

DPCosts = 2.7 * NumBarges;

end (*DPS*)

end (*BargeMoor*).
Procedure MethanolPlantCosts:

(*This procedure computes the cost of the methanol plant(s)*)

var RemPlantCap:

(*The remaining capacity in metric tons per day, after
3000 mt/day have been taken out for each barge*)

wages: (*the total wages of all the workers per year*)

Utilities: (*water, electricity, and catalyst costs for plant*)

PlantMaint: (*Plant maintenance costs*)

PlantInsurance: (*Plant insurance costs*)

begin

begin (*MethanolPlantCosts*)

RemPlantCap := trunc(PlantCap) and 3000;

if PlantCap<=3000 then

RemPlantCap := PlantCap;

else

RemPlantCap := 600. (*same for 600 mt. ton/day or less*)

end;

PlantCost := 15.1*(Plant Cap -3. 0e-5*PlantCap*PlantCap;

end;

PlantMaint := 7. 2e-6*PlantCost/PlantCap; (*Plant Maintenance*)

PlantInsurance := 0. 019+PlantCost; (*Plant Insurance*)

PlantCMCosts := Utilities+PlantMaint*PlantCap;

PlantCMCosts := PlantOnTime*3. 65*PlantInsurance+wages;

end; (*MethanolPlantCosts*)

**Procedure PlatCas.**

(*This procedure computes the capital cost and yearly expenditures for the platform and gas-processing equipment. Note that in certain arctic regions, these values are only theoretical, since a platform might not be installed there anyway due to the presence of icebergs. For depths over 700 feet, we propose (and use) using a tension-leg platform (TLP), and will assume that a TLP costs as much as a platform in 700 feet of water.*)

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```plaintext
var Plat3o: (*Cost of a 30 well platform*)
SeeDepth: (*A dummy variable for SeaDepth*)
wages: (*Yearly labor charges for platform alternative*)
PCCM: (*Yearly maintenance cost of platform and gas-processing equipment*)
PGinsurance: real;
PG: (*Yearly platform and gas-proc equip. insurance*)
begin (*PlatCost*)
SeeDepth := SeeDepth;
if SeeDepth > 700 then SeeDepth := 700;
if SeeDepth < 100 then SeeDepth := 100;
if zone = 'a' then begin (*a*)
   Plat3o := -10.688 + 0.5135 + SeeDepth - 1.231e-3*SeeDepth*SeeDepth
   + 1.56e-6*SeeDepth + SeeDepth^2*SeeDepth;
   wages := (crew - 25)*0.04;
end;
if zone = 'b' then begin (*b*)
   Plat3o := 195.9 - 0.662*SeeDepth + 4.316e-3*SeeDepth*SeeDepth
   + 3.42e-6*SeeDepth + SeeDepth + SeeDepth^2 + SeeDepth^3;
   wages := (crew - 25)*0.056;
end;
if zone = 'c' then begin (*c*)
   Plat3o := 29.8 - 1.02*SeeDepth + 6.474e-3*SeeDepth*SeeDepth
   + 5.414e-6*SeeDepth + SeeDepth^2 + SeeDepth^3;
   wages := (crew - 25)*0.088;
end;
if (SeeDepth > 100) and (SeeDepth < 700) then begin
   if NumWells < 6 then (*costs half of that for 30 wells*)
      Plat := Plat3o/2
   else
      Plat := Plat3o*(0.5 + (NumWells - 6)/48);
end (*for 100<SeeDepth<700*)
```

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```plaintext
else begin (*for 700<SeeDepth<1800*)
   if NumWells < 6 then
      Plat := Plat3o;
   else
      Plat := Plat3o*(1 + (NumWells - 6)/24);
end (*for 700<SeeDepth<1800*)
```

198

```plaintext
GasEquip := Plat3o/14;
PGinsurance := 0.06*(Plat3o + GasEquip);
PCCM := 0.02*(Plat3o + GasEquip);
```

199

```plaintext
PlatGascosts := PG/PlatGasinsurance+wages;
```

200
**Procedure PlatComp:**

(*This procedure computes the cost of drilling from a fixed platform or from a tension-leg platform (TLP). For a TLP, subsea completion costs must be added to the drilling costs*)

```plaintext
var FixPlatDCCosts: (*Drilling and completion costs from a fixed platform*)
TLPCosts: real; (*Drilling and completion costs from a TLP*)
```

**Procedure FixedPlat:**

(*Computes drilling and completion costs for a fixed platform*)

```plaintext
var FixPlatStd: real;
(FixPlatDCCosts = FixPlatStd*Frac(I+0.01+(Downtime-6.4)))*NumWells;
(Total DC (drilling and completion) costs, taking into account actual depth (by multiplying by FRAC), and actual number of wells)```

**Procedure TLP:**

(*This procedure computes the DC costs for a TLP*)

```plaintext
var TLPStd: real; (*DC costs for standard conditions*)
TLPDrill: real; (*TLP drilling costs*)
```

**Procedure Pipeline:**

(*This procedure computes the capital cost and yearly expenditures of the pipeline project. Note that trenching is optional in areas such as those whose water depths exceed 1,000 feet or where there is no danger of fishing trawls or anchors damaging the pipelines.*)
trenched to avoid ice scouring and damage to the pipeline.*)

```plaintext
var
Diameter, (*Outside diameter of pipe: 12.75-48 inches*)
PipePrice, (*Price of pipe in $ per foot*)
DepthFactor, (*Adjusts for pipe cost depending on sea depth*)
PipeMatCost, (*Total cost of materials for pipe*)
PipeWeight, (*Weight of pipe, in million of ton/foot*)
TurbineCost, (*Compressor turbine cost*)
ConcreteCost, (*Cost of concrete coating and anodes*)
FreightCost, (*Freight cost of pipe*)
TrenchLayRate, (*Trenching speed, in feet/day*)
PipeLayRate, (*Pipe-laying speed, in feet/day*)
TrenchVesselRate, (*Day rate of trenching vessel, millions of $/day*)
LayVesselRate, (*Day rate of laying vessel used*)
JobCosts, (*Haulization costs of laying and trenching vessels*)
PipeLayCost, (*Total pipe laying costs*)
MiscPipeCosts, (*Misc. pipeline costs, assumed to be 20% of rest of costs*)
PipeInsurance, (*Yearly pipe insurance costs*)
real,
begin (**Pipeline**)
Diameter = 1.2*sqrt(flow); (*flow is the fields flow capacity in mcf/day*)
if Diameter<12.75 then
  Diameter = 12.75;
if Diameter>48 then
  Diameter = 48;
DepthFactor = 1+1.5e-3*SeaDepth;
case zone of
  'a' PipePrice = (2.872*Diameter-19.4)*DepthFactor;
  'b' PipePrice = (7.079*Diameter-38.9)*DepthFactor;
  'c' PipePrice = (14.36+Diameter-97.0)*DepthFactor;
end; (*of case statement*)
PipeMatCost = PipePrice*ShoreDistance*1.0e-6;
(*the 1.0e-6 is to convert to millions of $*)
PipeWeight = 1.3439-3*Diameter-0.027*DepthFactor;
TurbineCost = 3.447e-6*ShoreDistance;
ConcreteCost = 0.35*PipeMatCost;
FreightCost = PipeWeight*ShoreDistance*2.0e-4;
case PipeLayVessel of (*this is for zones a and b*)
  0: PipeLayRate = 3100-25*(Diameter-12);
  1: PipeLayRate = 4530-37*(Diameter-12);
  2: PipeLayRate = 6510-52.5*(Diameter-12);
  3: PipeLayRate = 8050-65*(Diameter-12);
end; (*of case statement*)
case zone of
  'c' then (*changes above to fit zone c*)
  PipeLayRate = 0.6*PipeLayRate;
end (**Pipeline**)

if Trenching='y' then
begin (**trenching**)
TrenchLayRate = 10000.0; (*feet/day*)
TrenchVesselRate = 0.15; (*million $/day*)
if zone='c' then
begin (**zone c**)
  end; (**trenching**)
end; (**Pipeline**)
```

---

*Note: The text contains complex mathematical formulas and logic statements, which might be difficult to read without proper context and understanding of the variables and their definitions.*
TrenchVesselRate = 0.0; (* million $/day*)
end. (*zone c*)

end (*trenching*)
else (*no trenching*)
  TrenchVesselRate = 0.0;
end; (*of case statement*)

The following is for zone a)

Case PipeLayVessel of
  0: LayVesselRate = 0.17; (* millions of $*)
  1: LayVesselRate = 0.147;
  2: LayVesselRate = 0.214;
  3: LayVesselRate = 0.267;
end; (*of case statement*)

MobCosts = 1.785; (* mobilization cost of vessels*)

if zone='b' then
  begin (*zone b*)
    LayVesselRate = 1.25*LayVesselRate; (* 1.25 times that of zone a*)
    MobCosts = 2.1;
  end. (*zone b*)
if zone='c' then
  begin (*zone c*)
    LayVesselRate = 2.0*LayVesselRate; (* twice that of zone a*)
    MobCosts = 3.0;
  end. (*zone c*)

PipeLayCost = LayVesselRate*ShoreDistance / PipeLayRate
  + (100/(S0-LayVesDT));
  (* LayVesDT is the pipe-laying vessel's downtime, that's not mechanically related*)
TrenchCost = TrenchVesselRate*ShoreDistance / TrenchLayRate
  + (100/(S0-TVDT));
  (* TVDT is trench vessel downtime, excluding mechanically related downtime*)
MiscPipeCosts = 0.2*(PipeLayCost+TrenchCost);

PipeProjectCost = PipeMatCost + ConcreteCost + PipeLayCost
  + TrenchCost + MiscPipeCosts + FreightCost
  + MobCosts + TurboCost;

PipeInsurance = 0.01*PipeProjectCost;
PipeOMcosts = 0.015*PipeProjectCost + PipeInsurance;
end. (*PipeLine*)

Procedure TankerTransport:
(*This procedure computes the cost of methanol transportation to shore via shuttle tankers*)

var TankerRate real; (* Tanker rental rate / trip-ton capacity *)
begin (*TankerTransport*)
  TankerRate = 6.45 + 3.6364*ShoreDistance; (* for zones a,b *)
end; (*TankerTransport*)
TankerRate := 1.4 * TankerRate; (* 1.4 times more than for items a and b *)

TransportCost := 1.33 * TankerRate * NumBarges;

(* 1.33 47500 dwt * 1.0e-6 (conversion to millions of $) * 20 (trips/year) *)
Procedure MethanolAlternative;
(*This procedure determines and prints the total capital costs and expenditures of the alternative method: methanol production*)

begin (*MethanolAlternative*)
var CapitalCosts, YearlyOMcosts: real; (*dummy variables*)

CapitaCosts = DrillingCosts + SubseaCosts + BargePrice + MooringCosts + PlantCost;
AltCapCost = CapitalCosts;

(*Total capital costs of methanol alternative*)

YearlyOMCosts = SubseaCosts (+subsea OM costs*)
+ BargeOMCosts + MooringOMcosts
+ PlantOMCosts + TransportCost;
AltYearlyCost = YearlyOMcosts;

(*Total yearly oper. and maint. costs*)

end; (*MethanolAlternative*)

Procedure ConventionalTotal;
(*This procedure determines and prints the total capital costs and yearly expenditures of the conventional method of gas production*)

begin (*ConventionalTotal*)
var CapitalCosts, YearlyOMcosts: real; (*dummy variables*)

CapitalCosts = Plant + CasEquip + PlantDCcosts + PipeProjectCost;
ConvCapCost = CapitalCosts;

YearlyOMCosts = PlantCesCosts + PipeOMcosts;
ConvYearlyCost = YearlyOMcosts;

end; (*ConventionalTotal*)

Procedure RatioInfo;
(*This procedure prints out a table of ratios, comparing costs of the methanol alternative with the conventional method*)

begin (*RatioInfo*)
write(ratiofile, 'Methanol alternative to conventional method');
writeln(ratiofile, 'Ratios');
writeln(ratiofile, 'Capital Costs Yearly Costs');
writeln(ratiofile, AltCapCost/ConvCapCost: 8:2);
writeln(ratiofile, AltYearlyCost/ConvYearlyCost: 8:2);
end; (*RatioInfo*)
In the context of the methanol alternative, Table 1 presents a table of capital costs. The table includes the following components:

- Drilling Costs
- Subsea Costs
- Barge Price
- Moorings Costs
- Plant Cost
- Drilling Subsea Costs

The table is structured as follows:

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
<th>% of Cost</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling Costs</td>
<td></td>
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<td></td>
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<tr>
<td>Subsea Costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barge Price</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Moorings Costs</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Plant Cost</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Drilling Subsea</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Procedure Table 1:

(*Prints out a table of the capital costs for the methanol option*)

begin (*Table 1*)
write(AlternativeCap, 'Capital Costs of the methanol alternative');
write('by component in millions of 1980 dollars');
write(AlternativeCap, 'Drilling Subsea');
write(AlternativeCap, 'Barge Flooring');
write(AlternativeCap, 'Plant Total');
write(AlternativeCap, 'Equipment');
write(AlternativeCap, 'Cost');
write(AlternativeCap, 'cost % of cost % of');
write(AlternativeCap, 'total total');
write(AlternativeCap, 'count', DrillingCosts);'
write(AlternativeCap, 'count', SubseaCosts);'
write(AlternativeCap, 'count', BargePrice);'
write(AlternativeCap, 'count', MooringsCosts);'
write(AlternativeCap, 'count', PlantCost);'
write(AlternativeCap, 'count', AltCapCost);'
end (*Table 1*)

begin(*main*)
writeIntOut('Is input from file (y or n)');
break(termout);
readln(term);
read(term, file);
Description; (*Gives a program description, if the user wants it*)

Count := 1; (*Sets the field number in the data set = one*)
repeat(*note to O: find better way to rerun program*)
Input:
DrillCosts:
Subsea:
writein('The total drilling cost is (millions of $)', DrilgCosts);
writein('Total subsea completion costs are', CompCosts);
writein('Total manifold costs are', ManiCosts);
writein('Total flow line costs are', FloLnCost);
writein('Total subsea costs are', SubseaCosts);
SubseaOff;
BargeCosts:
writeln('Total barge price is: ', BargePrice: B: 2, ' million $');
writeln('Total barge yearly operating and maintenance costs are: ');
writeln(BargeCMCosts: B: 2, ' million $');

BargeMooring:
writeln('Barge mooring costs are: ', MooringCosts: B: 2, ' million $');

MethanolPlant:
writeln('Total Methanol plant cost is: ', PlantCost: B: 2);
writeln('Yearly plant operat. and maint. costs are: ', PlantCMCosts: B: 2);

Pipeline:
writeln('Pipeline project cost is: ', PipeProjectCost: B: 2, ' millions $');
writeln('Pipeline OM costs: ', PipeOMCosts: B: 2, ' millions $');

TankerTransport:
write('Tanker transport cost per year: ', TransportCost: B: 2);
write(' millions $');

MethanolAlternative:
write('Total methanol alternative costs are: ');
writeln(AltCapCost: B: 2, ' millions $');
writeln('Total methanol alternative yearly costs are: ');
writeln(AltYearlyCost: B: 2, ' million $');

Conventional:
writeln('Total conventional method capital costs are: ');
writeln(ConvCapCost: B: 2, ' million $');
writeln('Total conventional method yearly costs are: ');
writeln(ConvYearlyCost: B: 2, ' million $');

write(termout, AltCapCost/ConvCapCost: B: 2);
writeln(termout, AltYearlyCost/ConvYearlyCost: B: 2);

Table1:

RatioInfo:

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