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A Research Planning Study For Canada's Frontier Oil And Gas
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Canada's Frontier Oil and Gas

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A Research Planning Study for Canada's Frontier Oil and Gas

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Executive Summary

Oil and gas is an important energy source for Canada. Currently, about 60% of Canada's energy usage is oil and gas. Despite concerns about the effects of fossil fuels on the atmosphere, there are no competing fuels on the horizon, and oil and gas is expected to be the dominant energy source for many decades. Yet, Canada's conventional sources in the Western Canada Basin are in decline, especially oil. If alternative domestic sources of oil are not found, then imports will increase. If only half of our current oil consumption has to be imported, the annual import cost will be about $6 Billion. Yet, Canada is well-endowed with oil, but most future supplies are from high-cost sources such as the oil sands, the Frontiers and enhanced oil recovery of existing reservoirs. Therefore, there appears to be a strong rationale to focus research on ways of making these supplies competitive with imported oil, and hence, bringing them to market.

A significant national research effort on oil and gas is undertaken by the Federal Government through its Program on energy R & D (PERD). Currently, about $16 million is spent within this program on research relating to light-medium crude oil and gas, mainly from the Frontiers.

This planning study has been sponsored by PERD in recognition of the benefits in achieving a focus on research to improve the competitiveness of Canada's Frontier oil and gas, and hence its value to the Nation.

The study objectives and approach were, to:

- identify Frontier oil and gas developments which are already marginally economic or could be economic given plausible technology improvements through research.
- Develop ideas for technology improvements and/or innovations which could sufficiently reduce operating and capital costs to create attractive economic developments.
- Define the R & D thrusts and strategies which would be appropriate for PERD.

In conducting the study, the contractor has consulted extensively with the key stakeholders in Canada's Frontiers. These include the oil and gas companies, federal government agencies and boards, regional government agencies and boards, industry associations, and technical experts, both in Canada and abroad.

Canada's Frontiers include the regions North of600 N latitude and the offshore. These are vast areas and overlay extensive sedimentary basins which have now been explored with the drilling of over 500 wells. Exploration results to date have resulted in the discovery of between 4 to 6 billion barrels of oil and about 44 trillion cu. ft. of gas. This is less than had been hoped for, but still significant compared to the remaining reserves of the Western Canada Basin, (i.e. about 4 billion barrels).

Also, the ultimate potential of the Frontiers is greater at about 12 to 20 billion barrels of oil and about 130 trillion cu. ft. of gas. However, activities in the Frontiers at present are low because of the high cost of operations and development. This is aggravated by the poor cash flows of the oil companies and the depressed prices for oil and gas and their outlooks.

In this study, a number of generic oil and gas development scenarios have been examined in terms of the current perceptions of costs and their resulting economics. For each scenario, the major costs elements were examined and economic sensitivities were run with plausible reductions in these costs as might be achieved through focused R & D (or adaptation of innovative approaches which might need testing).

The results for Frontier oil are shown in Figure 1 and Table 1. It will be seen that there are a number of scenarios which can be economically attractive to develop, especially if costs can be lowered by 'technology uplift'.

The results are shown in terms of oil price, which is assumed to stay flat at $20 US for the foreseeable future. Also, shown in Table 1 for each scenario is whether additional reserves are necessary to achieve the economics shown. This is the case for some scenarios based on pipelines, because the pipeline tariff is dependent on running the pipeline full for its 20-25 year life.

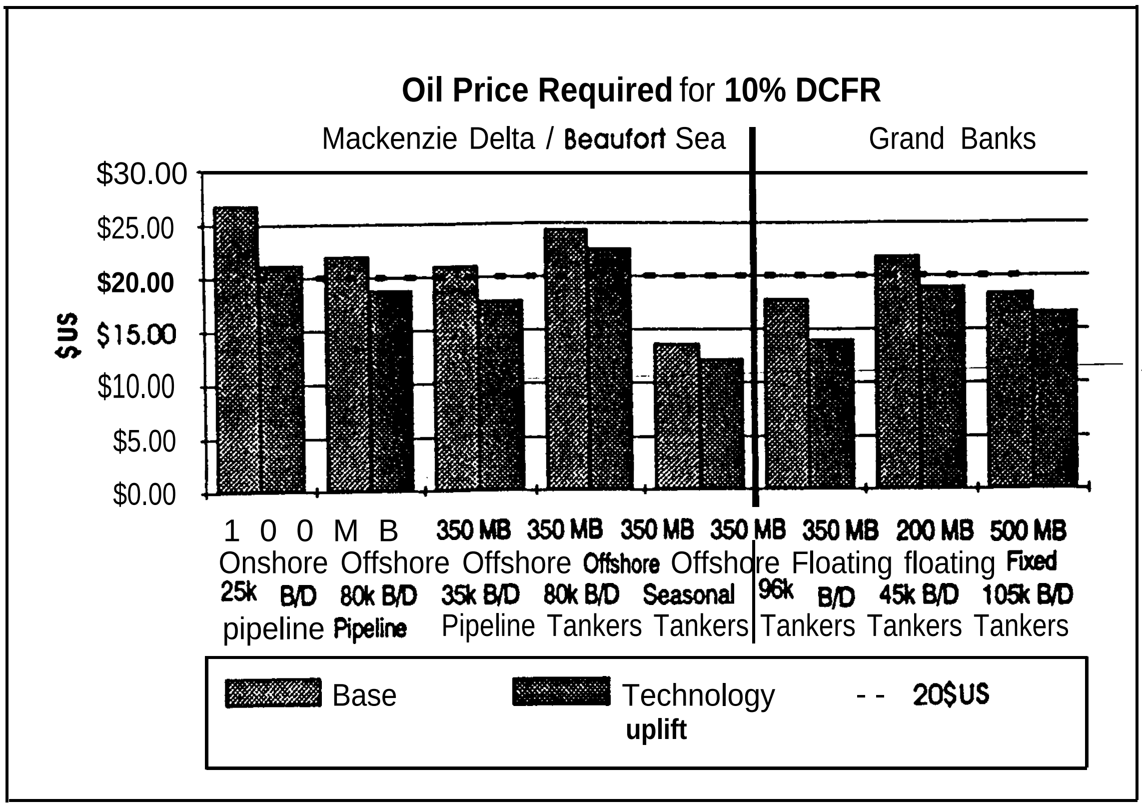


Figure 1

	Mackenzi Delta / Beaufort Sea					Gmnd Banka		
	100 MB Onshore 25k B/T) Pipeline	350 MB Offshore 80k BID Pipeline	350 MB Offshore 35k B/D Pipeline	350 MB Offshore 80k BID Tankers	350 MB Offshore Seasonal Tankers	350 MB Floating 96k BP Tankers	200 MB Floating 45k B/D Tankers	500 MB Fixed 105k B/C Tankers
Base	$26.75	$22.00	$21.00	$24.40	$13.60	$17.75	$21.80	$18.40
Technology Uplift	$21.20	$18.80	$17.80	$22.60	$12.20	$14.00	$19.00	$16.60
Additonal Reserves Required	200 MB Onshore or Near Offshore	600 MB	0	600 MB (or less if tanker can be re-deployed)	0	0	0	0

MB. million barrels B/D - barrels per day

Table 1

It will be noted that there are several scenarios which could be economically attractive without additional reserves if focused research can achieve lower costs. These include:

- A small Beaufort oil development, using an extension of the Norman Wells line or tanker transportation.

- Floating production of Grand Banks oil, including the smaller fields.

Natural Gas development scenarios for the Frontiers have also been examined. It is concluded that only offs hore Nova Scotia gas is within striking distance of being economic, given the current outlook for natural gas prices. It also concluded that this scenario can be enhanced by a focused R & D effort.

This study recommends that the PERD program for Frontier oil and gas be focused on the three scenarios mentioned above: i.e.

- Small Beaufort Oil Development
- Grand Banks Floating Production
- Offshore Nova Scotia Gas Development

Not only have the above-mentioned scenarios a good chance of being economically attractive, given technology uplift, but, they also achieve a regional balance.

Key research areas which should be addressed in relation to these scenarios are:

- Offshore platforms in ice
- Offshore pipelines in ice-scoured regions
- Development drilling and completions
- Pipelines through permafrost regions
- Arctic tankers and terminals
- Floating production vessels and tankers for sea ice and iceberg-infested and stormy regions
- Integration of ice detection, ice avoidance and ice tolerance design for production vessels and tankers in marginal ice zones

- Subsea systems including multi-phase transport and metering, as well as ice scour protection of wellheads and flowlines

- Use of minimal platforms including unmanned facilities

Specific research thrusts in these areas are outlined in the report.

The recommended PERD strategy is to focus research mainly on the three previously identified scenarios. However, any technology advances achieved will likely benefit other Frontier scenarios, which may become attractive in the future as additional reserves are discovered, or prices rise.

In order to encourage further exploration, it is also recommended that some PERD resources be devoted to lowering the high-cost of Frontier exploration. Recommended research in this area is outlined in the report.

It is expected that the recommended strategy for Frontier research within PERD can be accommodated without changing the present committee structure. However, some enhancements are recommended. These include the creation of three Task Forces, one for each of the recommended scenarios. These Task Forces would develop the research needs and projects needed to economically enhance each scenario, as well as specifying the ancillary research needs for each scenario relating to regulation of safety and environmental impacts. These Task Forces would be working groups, not committees, and they would need a secretariat and leaders who could devote more than **50%** of their time to the task. They would report to the strategic planning committee of Task **6,** who would create or disband them as the overall strategy dictated.

If the scenario approach, as recommended from this study is adopted, then it is believed that the opportunities for collaborative research involving other stakeholders will be significantly enhanced. it is recommended that PERD fully exploit such opportunities which will help create a national alignment of effort on key scenarios and issues.

It must be emphasized that the objective of this study is not to promote specific Frontier development projects. Nor is it to persuade operators and governments to start planning for specific developments. The development scenarios were examined solely to help focus research on areas that could lead to, or enhance, economic developments. And conversely to help avoid putting research effort into areas which have little value in enhancing Frontier resources.

The attractiveness of aligning research to development scenarios which can be made economically attractive through improved technology is that progress can be made towards economic development without committing to large expenditures. Yet, by involving key stakeholders in planning and conducting the R & D, a common purpose and coordination of effort is maintained.

The benefits to Canada in adopting the approach recommended in this study are more than just creating wealth from it indigenous resources. Canada has extensive “Frontier regions’ and the ability to operate and develop improved technology for its Arctic and offshore areas is an issue of strategic and economic importance. Canadian organizations have already acquired considerable expertise in remote operations and engineering. Some of this expertise is now being tapped for applications in other parts of the world, such as Siberia. To maintain and enhance this expertise, a domestic focus is essential. This can be achieved if the recommendations made in this report are adopted.

Introduction

Study Goal

The overall goal of this study is to identify key research and development thrusts for Canada's Frontiers, which, if successful, will significantly improve costs and economics. such improvements would lead to the creation of additional wealth for the Nation, either by enhancing the economics of already economic potential developments, or, more importantly perhaps, triggering developments which are at present uneconomic.

The motivation for the study is driven by the need to ensure that the Federal Government's Program on Energy R & D (PERD) maintains its focus on priority issues, especially those which can lead to wealth creation. The study is sponsored by PERD but, because of its very pragmatic focus on costs and economics, it is expected that the outcome of the study will also be valuable to industry in setting its own research and technology priorities. Indeed, if alignment can be achieved on technology thrusts between the various stakeholders, then the likelihood of pursuing them effectively through collaborative ventures is much enhanced.

PERD and Frontier R and D

The Federal Energy R & D Program is coordinated by the Panel on Energy R & D (PERD) and involves thirteen federal departments and agencies. The program was started at the time of the first OPEC oil embargo in 1973, the main concern at that time was security of supply of energy (in particular oil).

Funding for PERD reached a maximum of about $170 million/year in 1984, Subsequent budget cuts have reduced the program to about $88 million in 1992/93. The formal objective of PERD is described as "to provide the science and technology for a diversified, economically and environmentally sustainable energy economy."

The Program is organized into seven broad technology areas called "tasks'. These are listed below with the approximate annual budgets.

Task 1- Energy Efficiency ($15M)

Task 2- Coal ($1OM)

Task 3- Nuclear Fusion ($8M)

Task 4- Renewable and Generic Environment ($11 M)

Task 5- Alternative Transportation Fuels ($21 M)

Task 6 - Oil, Gas and Electricity ($16M)

Task 7- Coordination and International Contributions ($7M)

Task 6 focuses mainly on conventional oil and gas (mainly the Frontiers). It is for Task 6 that this study is being conducted. Task 5 includes other petroleum topics such as oil sands, heavy oils and enhanced oil recovery.

The topics within Task 6 include petroleum geoscience, permafrost and gas hydrates, marine engineering, offshore geotechnics, materials, transportation of oil and gas, environmental forecasting and impacts, and a small electrical R & D component. Currently, most of the $16 million of the Task 6 annual budget is devoted to oil and gas.

The recently revised objective for Task 6 is as follows: "To support and develop regulatory, exploration, development, production and transportation sciences and technologies that will help Canada develop and produce light-medium crude oil and natural gas, principally from the Frontiers, in a safe, economic and environmentally acceptable manner.'

Task 6 has also recently been reorganized into three technical committees which steer the R & D. These are

- Engineering and Geoscience
- Environment
- Transportation

Each committee has representation from departments whose mandates and expertise include Frontier oil and gas activities. These departments also submit proposals for R & D to the committees. The oil and gas industry is represented on the committees with 2-3 persons nominated by CPA (now CAPP). However, the industry representatives cannot bring projects to the table, but do provide advice and comments. During recent years the industry has supplied annually its perspective on research priorities. This has been done in a regional and scenario format (e.g. Grand Banks, floating production). Table 2 shows the resulting matrix of priorities in terms of scenarios and technical areas. This input to the PERD committees is accompanied by an overview and detailed commentary. (CPA, 1992). Naturally, the industry input does not reflect government priorities or departmental mandates, but is does represent a rational process for defining R & D priorities.

Historically, the Task has been heavily oriented towards regulatory needs. This was probably appropriate for periods of high activity in the Frontiers when governments needed the knowledge to develop regulations, and the general expectations were that Frontier oil and gas would be economic with the technology being used or being developed (primarily by industry). Today, the situation is quite different, mainly in terms of price expectations and reserves.

New Realities and Rationale for the Study

As shown in Figure 2, oil price has varied considerably during the existence of PERD. In fact, during the period 1973 to 1985, oil price reached well over $40/barrel, driven largely by OPEC policies. At the same time, Canada seemed well-endowed with potential oil reserves, albeit in difficult places like the Frontiers and the oil sands. At the time, Frontier potential was estimated to be over 40 billion barrels of oil and over 200 trillion cu. ft. of gas. Under these circumstances, industry activity was high and R & D was aimed at viable operating technologies almost regardless of cost. The Petroleum Incentives Program (PIP) also encouraged activity in the Frontiers.

To date, over 500 wells have been drilled in the Frontiers and significant discoveries have been made, but, well below expectations. As shown in Table 3, some industry analysts (e.g. Dingwall, 1990) assess total Frontier oil discoveries of about 3.4 billion barrels, well below the 40 billion barrels expected. On the other hand, total potential is estimated at between 11.6 billion barrels and 20 billion barrels. To put these figures in perspective, the remaining reserves of the Western Canada Basin are estimated at about 4 billion barrels.

Table 2 (CPA, 1992)

CPA/PERD TASK 6.0 PRIORITIES (REVISED MAY, 1991)(RE-CONFIRMED, APRIL 1992)

Operating Scenario	Topic	Environmental: Chronic Impact	Environmental: Baseline Assessment	Environmental: Effects Monitoring	Environmental: Oil Spill	Safety and Evacuation	Sea Floor Issues	Engrg and Design	Sea State and Weather Forecasting	Wave and Current Criteria	Ice Detection Forecasting And Management	Ice/Structure Interaction	Permafrost	Development Probability
Grand Banks	Fixed Plat. Plat.	M/M/H	L	H	H	H	M(4)	M(1)	M(4)	L	H	M/H	N/A	1 -
	Float Plat.	M/H	L	H	H	H	L	L/M(8)	M	L	H(5)	M/H	N/A	
	Pipeline/ Wellhead	L	L	H	H	N/A	H	H	N/A	L		H	N/A	
	Tankers	L	L	H	H	L	N/A	H(4)	L	L	H(7)	L	N/A	
	Exploration	L	L	H	H	H	L	L	M	L	M	L	N/A	
Nova Scotia	Fixed Plat.	M/H	L	M	M	H	M	L	M	L	N/A(2)	N/A(2)	N/A	1 -
	Float Plat.	L	L	L	M	H	L	L	M	L	N/A(2)	N/A(2)	N/A	
	Pipeline	L	L	L	M	N/A	L	L	N/A	L	N/A	N/A	N/A	
	Tankers	L	L	L	M	L	N/A	L	L	L	N/A	N/A	N/A	
	Exploration	L	L	L	M	H	L	L	M	L	N/A	N/A	N/A	
Beaufort Offshore	Platform	M/H	L	M	H	H	H	M/H(1)	L	M(3)	L(6)	H	H	3
	Offshore Pipelines	M/H	L	M	H	N/A	H	H	N/A	L	L	H	M	
	Onshore Pipelines	L	L	M	L	N/A	N/A	H	N/A	N/A	N/A	N/A	H	
	Tankers	L	L	L	H	L	N/A	M	L	L	H(7)	L	N/A	
	Exploration	L	L	L	H	L	L	M/H	L	L	M	M/H	L	
Beaufort Onshore	Production	L	L	L	L	L	N/A	M	L	N/A	N/A	N/A	H	2
	Onshore Pipelines	L	L	M	L	N/A	N/A	H	L	N/A	N/A	N/A	H	
	Exploration	L	L	L	L	L	N/A	L	L	N/A	N/A	N/A	L	
High Arctic	Fixed Plat.	N/A	L	N/A	N/A	H	L	H	L	L	L	H	M	4
	Float Plat.	N/A	L	N/A	N/A	H	L	H	L	L	H	M	L	
	Pipelines	L	L	L	H	N/A	H	H	N/A	N/A	N/A	L	H	
	Tankers	L	L	L	H	L	N/A	M	L	L	H(7)	L	N/A	
	Exploration	L	L	L	H	H/M	L	L	L	L	M	L	L	
West Coast Exploration		N/A	L	N/A	N/A	H	L	L	M	L	N/A	N/A	N/A	5
Georges Bank Exploration		N/A	L	N/A	N/A	H	L	L	M	L	N/A	N/A	N/A	
committees				6B		6A	6A	6A 6C	6B	6B	6B, C	6A, 6C	6A 6C	

CEC44

NOTES:

1 CSA verification program, high priority
2 For k. Ire. Nova Scotia waters
3 Storm erosion on hybrid structures
4 loading
5 Integrated detection ●"h- forecasting
6 Ice island inventory
7 Detection
a "Low" for ice avoiding structure, "medium" for k. tolerant structure

ESTIMATED RECOVERABLE RESERVES

AREA	LIQUIDS Bbls	GAS Tcf
Offshore British Columbia	.	.
Yukon Territory	0.005	0.3
Central & Southern NWT	0.305	0.5
Beaufort Sea I Mackenzie Delta	1.000	12.0
Arctic Islands	0.455	17.0
Labrador	-	5.0
Grand Banks	~~0.135~~ 1.5	4.0
Nova Soctia	0,135	5,0
Total	3.4	43.8

(

ESTIMATED ADDITIONAL POTENTIAL RESERVES

AREA	LIQUIDS Bbls	GAS Tcf
Offshore British Columbia	1.0	1540
Yukon TerritoryCentral & Southern NWT	0.5	4.0
Beaufort Sea/Mackenzie Delta &Northern NWT	2.5	24,0
Arctic Islands	0.5	15.0
Labrador		7.0
Grand Banks	3.0	5.0
Nwa Scotia	0.2	8.0
Hudson Bay/Maritimes	0.5	1.5
Total	82	7%.5

Oil Price: 1950-1990 **(EMR,1990)**

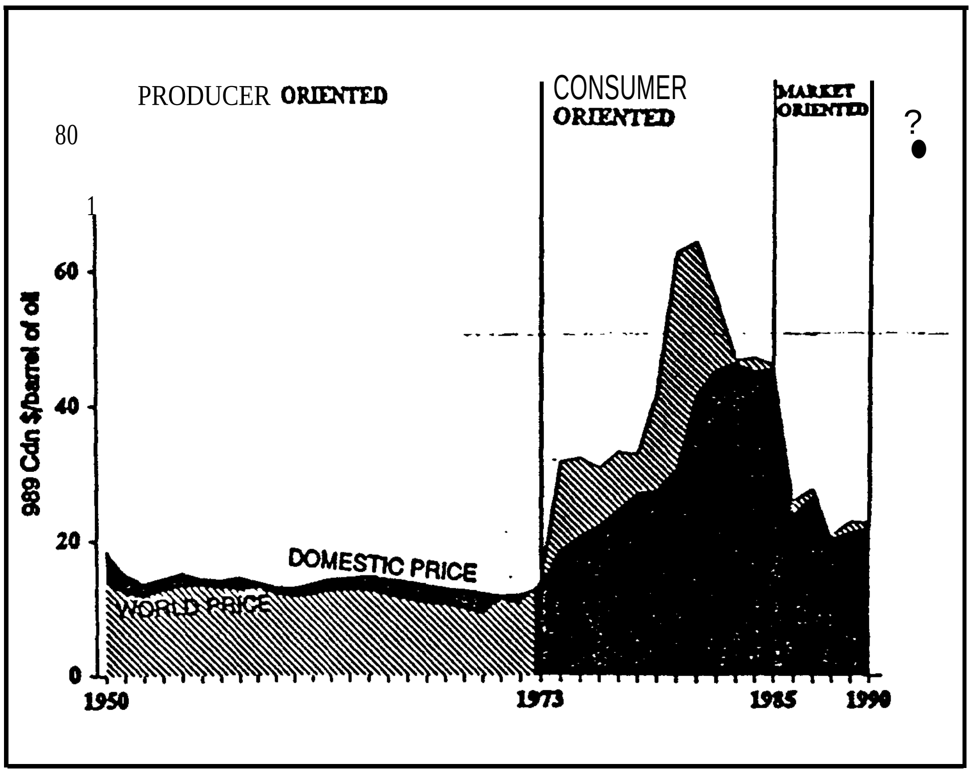


Figure 2

To **compound** the problem of lower than expected discoveries, the prospects for the Frontiers have also been hit by the dramatic drop " in oil prices after 1986. Today, **the** oil price hovers around **$20/barrel** and **the current** view is **that** no real growth in price (other than inflation) can be counted on.

This lower oil price, together with depressed natural gas prices, has also led to significantly lower profits (and in many cases, losses) for the industry. This has also reduced the appetite of the industry to get involved in high-cost **Frontier activities.**

These are the new realities which have resulted in a dramatic drop in Frontier activities and plans. This change **leads** to the question of what **PERD's** future role and **activities** relating to the Frontiers should be? A question which this **study** will address.

A simple conclusion, based on current fashions, would be that PERD should significantly reduce its research on oil and gas. After all, it could be argued, Canada's oil and gas industry is in decline and fossil fuels contribute to CO_2 in **the** atmosphere; wouldn't we be better off focusing on other forms of energy?

This argument has some validity, but, there is another perspective which would lead to different outcome.

It is certainly appropriate to strive for more environmentally friendly energy sources, but it would seem foolish to base future plans on unknown break-throughs which would be needed to provide such sources on the scale required. In the meantime, Canada's energy future will continue to be dominated by oil and gas, at least, for the next several decades. The energy demand for fuel as predicted by the Canadian Government is shown in Table 4. As can be seen, the percentage demand for oil and gas is not expected to change significantly through-201 O. That is, oil and gas are predicted to make up about 60°A of Canada's energy sources for several decades. Also, because total demand is predicted to rise, the total oil and gas requirements will actually be higher.

Canadian Energy Demand by Fuel (% of Total) **(EMR,1990)**

	1974	1990	2010
Oil	38	36	31
Natural Gas	28	26	27
coal	7	12	12
Hydro and Nuclear	27	21	25
Renewable	0	5	5
%	100	100	100
Total Demand (Peta Joules)	8000	9600	13,800

Table 4

If this forecast is correct, then, the next question is; from where will this oil and gas be produced? Looking at oil, Canada's current production is about 1.25 million barrels per day, which is produced mostly from Western Canada Basin (WCB), which has about 4 billion barrels remaining to be recovered (i.e. its reserve life index is about 9- 10 years). Furthermore, it is generally believed that prospects for future discoveries are not good. So, the issue of future oil supplies for Canada will be solved by one or more of the following approaches:

1. Reduce consumption

2. Displace crude oil by natural gas
3. Increase the use of synthetic oil from the Oil Sands
4. Increase recovery from existing WCB reservoirs
5. Produce oil from the Frontiers
6. Increase imported oil

A combination of all of the above responses will likely be the appropriate outcome (each has its own benefits and problems).

It is important to recognize, however, that in a free market economy, the Canadian supply alternatives, 2 through 5, will only occur if supply costs can be kept below world prices. But, the Canadian supply alternatives are generally high-cost, hence, the slowdown in energy projects and the current dilemma

On the other hand, it is clearly to Canada's benefit to develop its indigenous oil rather than importing it. If Canada ultimately has to replace all its current production with imported oil, then the annual cost to the nation will be about $11 billion, this would have a disastrous effect on our balance of payments. Furthermore, development of indigenous resources has many spin-off benefits including regional development and job creation, as well as the development of technology which can ultimately be exportable.

One lever that can be used to strive for lower supply costs is improved technology and knowledge gained through focused research and development.

In fact, significant technology improvements have already been part of Frontier exploration and development to date. Canada has become a world leader in developing technology to operate safely in the Arctic and ice-infested regions. Future research thrusts can build on this existing superior knowledge, but should obviously be aimed at lowering the costs of future supplies through innovation.

It is recognized that in the Frontiers, much less oil and gas has been discovered than hoped for. But, as shown in Table 3, the reserves discovered to date and the future potential are quite significant, especially compared to the four billion barrels remaining in the WCB. Using current prices, the size of the prize is in the range of $100 billion to $300 billion.

It can be argued, therefore, that the rationale is very strong for PERD Task 6 to focus on maximizing Canada's Frontier oil and gas competitiveness and, thereby, its value to the Nation. For this to happen, it is essential that the R & D be focused on initiatives which can lead to lower costs. But, these need to be within development scenarios which are either marginally economic now, or could be economic if costs are lowered (in some cases combined with additional discoveries).

In order to achieve this focus, it is first necessary to understand the current perceptions, costs and economics, and second identify technology opportunities to lower costs. This study 'is–aimed at achieving such an understanding.

Study Objectives

1. To identify Frontier oil and gas developments which are either already marginally economic or could be economic given plausible technology improvements.

2. Develop ideas for technological improvement and/or innovations which could sufficiently reduce capital and/or operating costs to create attractive economic projects.

3. Define appropriate R & D thrusts and strategies especially for PERD Task 6.

Study Approach

The overall approach and logic to be used in the study is defined in Figure 3. In order to implement such an approach in a well quantified manner, one would actually have to follow a much more detailed logic, as shown in Figure 4. The scope of this study does not allow for such a detailed analysis, especially in the context of deriving the required information from scratch. However, by using information supplied by the operators, by government agencies, and using the experience and knowledge of the authors, it has been possible to follow a similar analysis. (At least, partially in the context of selected key scenarios.)

Significant effort has been placed on interaction with the stakeholders to ensure that the current situation is well understood, and that ideas for technology improvements are captured from a wide range of sources.

Of particular importance has been the need to understand the current situation in terms of discoveries to date, potential, exploration and development technologies, costs and economics and the currently perceived barriers. These **will** be discussed later in the report.

In order to achieve consistency across scenarios, we have used a common economic analysis and assumptions. For each scenario we have **analyzed** the sensitivity of the economics to a **variety** of parameters including oil **price, costs,** field size, etc.. From these sensitivities, it has been possible to appreciate very precisely the **potential** benefits, **(i.e.** the size of the prize) which could be achieved through improved technology and **knowledge**. For each scenario, from such an analysis, general technology goals can be defined and then ranked within and across scenarios. From this overall assessment, specific R & D thrusts have been recommended.

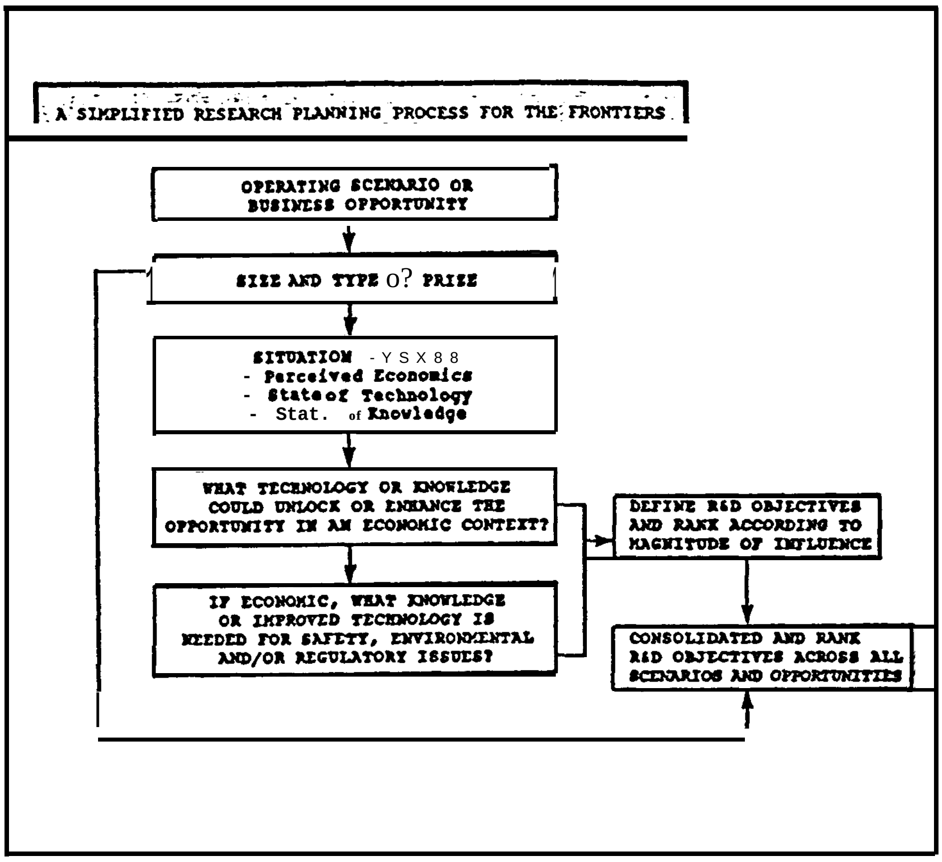


Figure **3**

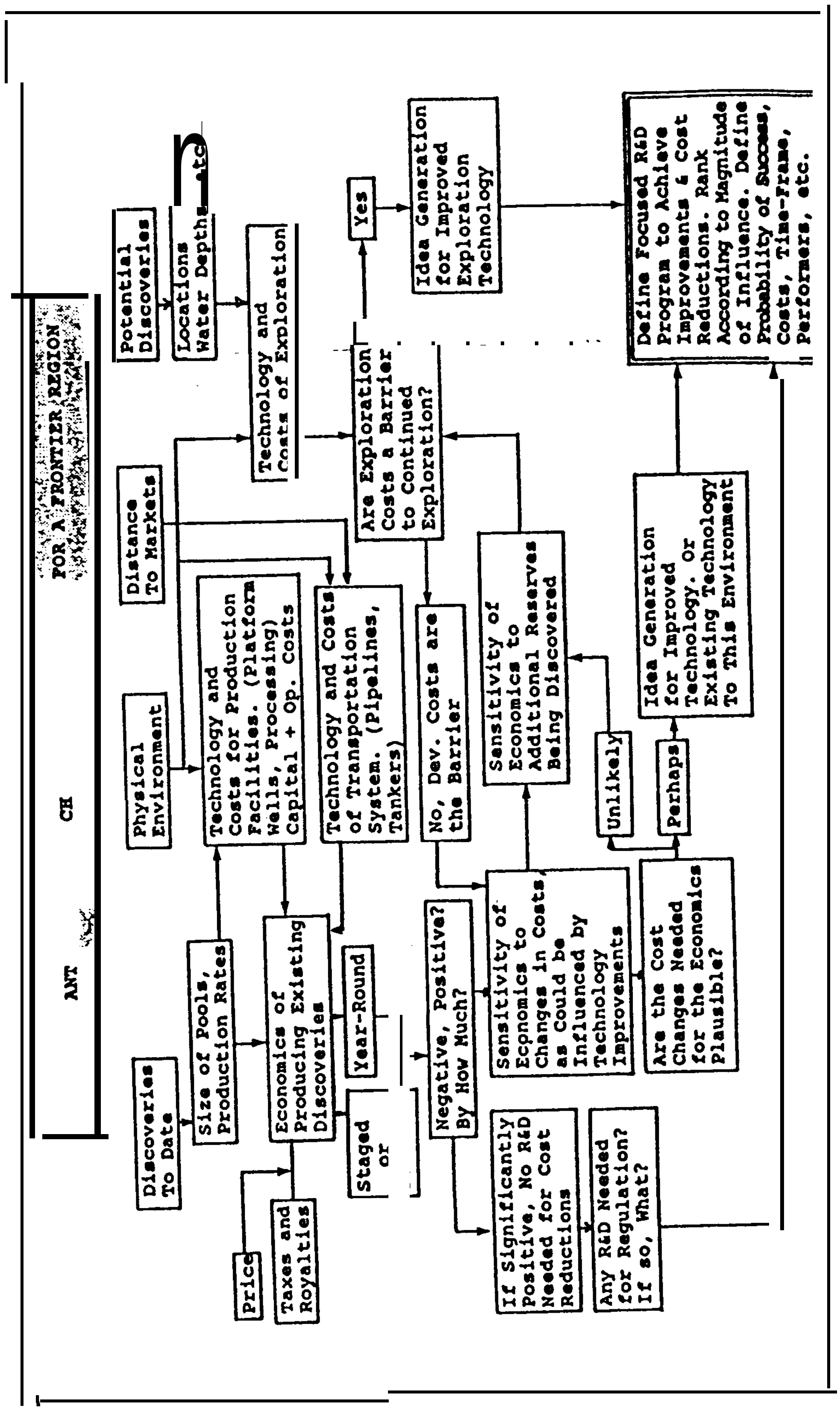

FOR A FRONTIER REGION
Discoveries To Date
Size of Pools, Production Rates
Economics of Producing Existing Discoveries
Price
Taxes and Royalties
Staged or
Year-Round
Physical Environment
Distance To Markets
Potential Discoveries
Locations Water Depths, etc
Technology and Costs of Exploration
Technology and Costs for Production Facilities. (Platform Wells, Processing) Capital + Op. Costs
Technology and Costs of Transportation System. (Pipelines, Tankers)
Are Exploration Costs a Barrier to Continued Exploration?
Yes
Idea Generation for Improved Exploration Technology
No, Dev. Costs are the Barrier
Negative, Positive? By How Much?
If Significantly Positive, No R&D Needed for Cost Reductions
Any R&D Needed for Regulation? If so, What?
Sensitivity of Economics to Changes in Costs, as Could be Influenced by Technology Improvements
Sensitivity of Economics to Additional Reserves Being Discovered
Are the Cost Changes Needed for the Economics Plausible?
Unlikely
Perhaps
Idea Generation for Improved Technology. Or Existing Technology To This Environment
Define Focused R&D Program to Achieve Improvements & Cost Reductions. Rank According to Magnitude of Influence. Define Probability of Success, Costs, Time-Frame, Performers, etc.

Figure 4

Overview of Canada's Frontier Oil and Gas

The Region and Geography

A map of Canada's **petroleum** regions is shown in Figure **5. By** definition, Canada's Frontiers include all of the offshore regions as well as onshore regions north of 60 degrees latitude. With such a definition it can be seen that a considerable area of the sedimentary basins which are prospective for oil and gas lies within the Frontier boundaries. The term "Frontier" has been coined for a reason. The areas north of 60 and offshore impose a harsh physical environment on operations and are often quite remote from centres of population and the marketplace. Onshore in Canada, regions north of 60 degrees, generally have permanently frozen ground (permafrost) which requires special engineering and operational procedures to avoid subsidence. Also, except for the West Coast and Nova Scotia, the water bodies covering the Frontier sedimentary basins are subject to ice of one form or another at some time of the year. In fact, in the Arctic Islands, the ice cover can be a permanent feature. It is this severe physical geography and the remoteness which significantly affect the cost of oil and gas operations in the Frontier Regions.

Exploration History

The earliest drilling north of 60 degrees resulted in an oil discovery at Norman Wells in 1920. This drilling had been stimulated by known oil seeps into the Mackenzie River. However, it was not until the 1960's that exploration started in earnest in the Frontiers. The first Arctic well was drilled at Winter Harbour, Melville Island in 1962 and this was followed by wells in the Mackenzie Delta/Tuk peninsula region, as well as the commencement of drilling off Nova Scotia and in the Gulf of St Lawrence. In the early 1970's an oil discovery was made at Atkinson Point in the Mackenzie Delta, and offshore exploration started on the Grand Banks. The first Arctic offshore well was drilled from an artificial island in the Mackenzie

Delta in 1973. In the mid 70's exploration drilling using drillships started in the Beaufort Sea and offshore wells were routinely being drilled from floating ice platforms in the Arctic Islands. Large gas fields were discovered in the Mackenzie Delta, off Labrador, Nova Scotia and in the Arctic Islands. In 1979, the Hibernia oil field was discovered followed by Terra Nova in 1934. The Amauligak oilfield in the Beaufort Sea was also discovered in 1984,

Canada's Petroleum Regions **(GSC, 1983)**

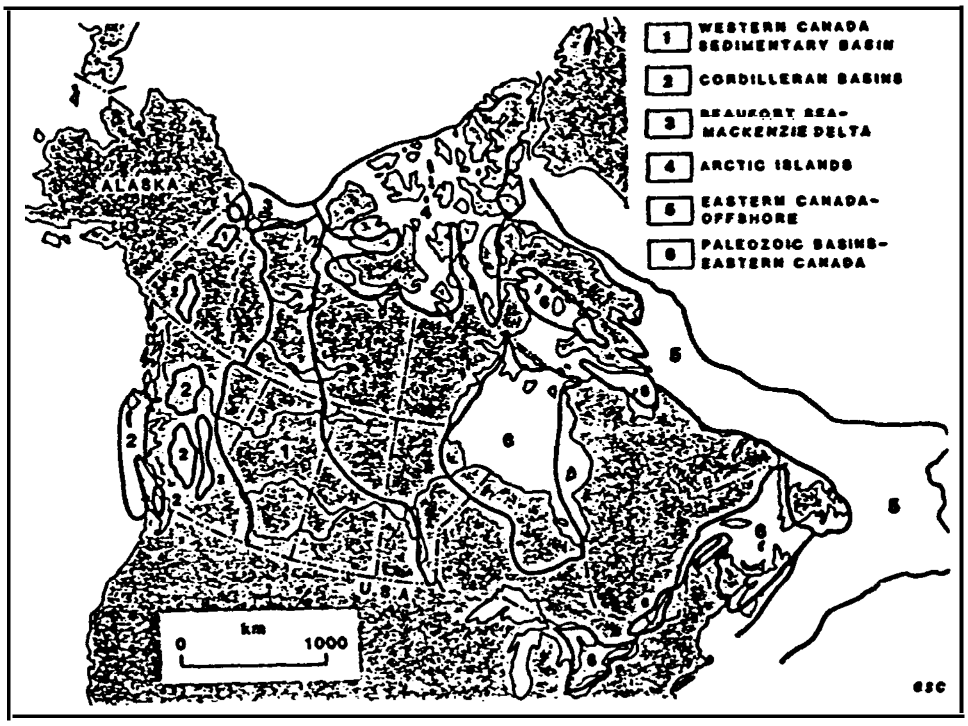


Figure 5

The distribution of the over 500 wells drilled in the Frontiers is summarized in Table 5 together with the number of significant discoveries. The quantities of oil and gas discovered and future potential have already been discussed and displayed in Table **3.**

Development Activities

Sixty-five years after oil was discovered at Norman Wells, oil production via a pipeline to the south began (although the oilfield had been tapped to produce refined product for the region for several decades). At the commencement of production in 1985, the Norman Wells reservoir was estimated to contain about 200 million barrels of oil and has been producing at about 30,000 barrels/day. Norman Wells is Canada's most northerly oilfield with sustained year round production.

Walls Drilled In the Canadian Frontiers (Dingwall, 1990)

Region	Wells Drilled	"Significant" Discoveries
Beaufort Sea/Mackenzie Delta	100+	35
Arctic Islands	170	18+
West Coast	14	0
Nova Scotia	100	25+
Newfoundland	90	20+
Labrador	27	7+
Hudson Bay	5	0
Totals	506	105

Table 5

About three hundred and fifty miles further north lies the Mackenzie Delta and the Beaufort Sea Although this region has oil discoveries totaling 1.0 to 1.5 billion barrels and gas discoveries of 12 trillion cu. ft., development has not yet occurred. On the other hand, considerable effort has been put into development planning, engineering, as well as regulatory and environmental reviews. A big initiative took place in the mid 70's when a consortium of producers and pipelines were proposing to produce the newly discovered gas reserves in the Mackenzie Delta. At that time, the outlook for gas prices was bullish, shortages in the U.S. were predicted, and the project was predicted to be very economic. Extensive public reviews and regulatory screening took place culminating in the Berger Report (1977) which recommended a moratorium of ten years on building a large diameter pipeline up the Mackenzie Valley. The project was shelved, but the concept of producing the large gas reserves from the Mackenzie Delta/Beaufort region was reactivated by the producers in 1987.

Again, the producers felt that natural gas supply and demand in the U.S. and rising prices would create the ingredients for an economic project. Also, several technical issues which had stalled the 1976

Even further to the North in the Arctic Islands, the Bent Horn oilfield on Cameron Island has been on seasonal production since 1985. The oil is produced to storage tanks and then to an Arctic Class 2 bulk carrier (the M.V. Arctic), which can generally make two shipments each summer for a total annual production of about 300,000 Barrels. Bent Hom contains only about 6 million barrels of oil, so the scope for extending this operation to a larger production is limited, but, some incremental production is being planned.

Off Canada's East Coast the Hibernia oilfield is located about 300 km east of St. Johns in 80 m of water. The reservoir is. estimated to contain about 600 million barrels of oil and a $6.2 billion development project is underway. Oil will be produced from a fixed platform to a shuttle tanker. The fixed platform is designed to resist iceberg impacts and high seas. The economics for this project are positive, but the project has required government incentives to encourage investment. Nevertheless, the project is of significant regional importance. It will also bring on a Canadian supply of crude oil of 110,000 barrels/day in 1997. Also the project will lead to infrastructure development which can help lower the costs of future development.

In addition to Hibernia, significant studies have been carried out for the development of Terra Nova, a 350 million barrel oilfield within 35 km of Hibernia. The Terra Nova partners have prepared designs for a floating production system, but, no development plan has yet been submitted. (As will be discussed later, floating systems for the East Coast appear to have more favorable economics).

Further south off Nova Scotia, Canada's third Frontier, and first offshore development, is on production. The small Panuke-Cohasset development taps into about 40 million barrels of oil using minimum jacket and modified jack-up structures, and a shuttle-tanker operating for 7 months of the year. By avoiding the stormy months, capital investment in the offloading system is reduced and the project is economic. The investment costs are modest because the area is ice-free and the water depth is only 40m.

Technology and Science

Operations and engineering in Canada's Frontiers have required new knowledge and special technology, most of which has been developed in Canada. When oil and gas exploration started about three decades ago, nobody knew how this technology would unfold, only that existing oil and gas methods as used in the south would need to be adapted, and in some situations, completely replaced by new methods. An early example of adaptation was in geophysical/seismic exploration, in permafrost regions. It was quickly recognized that the use of tracked-vehicles over the tundra, destroyed the vegetation, which in turn caused the permafrost to melt. This problem was overcome by only operating in winter and protecting the tundra with snow roads.

A more technically-challenging permafrost problem was that of drilling wells through permafrost To avoid surface subsidence, hole sloughing, and high casing stresses, a whole set of special drilling methods were developed. These included the refrigeration of the surface casing, the use of chilled drilling muds and special cements which cured without giving off excessive heat.

The challenge of building and operating pipelines through permafrost regions was also a new challenge and has been the focus of significant technology development. Again the issue of degradation of the permafrost during construction and during operation of the pipeline have been the main issues.

When the need to move offshore in Canada's Frontiers became apparent, a significant R & D program was initiated by the Canadian industry (often with the collaboration of government scientists). In 1969, ice mechanics, ice environment, and seafloor research was initiated for the Beaufort Sea. The main thrust at that - time was to develop safe design criteria for offshore platforms which it was anticipated would be needed for offshore drilling and production.

It is noteworthy that the industry players at the time recognized the need for collaboration in Frontier research. To this end, the Arctic Petroleum Operators Association (APOA) was formed in 1970 specifically to conduct joint-industry research. APOA sponsored over 200 research projects during its fifteen year existence. APOA was absorbed into the CPA Frontier Division in the mid-eighties and its research focus was lost. This was partly as a result of the creation of ESRF (Environmental Studies Research Fund) which was supported by an industry levy. A similar organization, the East Coast Petroleum Operators Association (EPOA), sponsored research relating to East Coast operations.

The collaboration achieved through APOA and EPOA is highlighted because it demonstrates that when a common need is recognized, industry is well-able and willing to collaborate in research programs. As discussed later, if alignment of PERD and industry research needs is achieved, then collaboration with industry will be very likely.

In the past, the emphasis of industry R & D was mainly on the development of knowledge and technology to achieve safe and environmentally sound operations. CostS were also a factor, but, particularly in the early days, costs were a secondary consideration because it was expected. that prices would continue to increase and create economic developments.

Research and Technology did deliver; increased understanding of Canada's Frontier environment was achieved; platforms to withstand the severe ice of the Beaufort were designed and built; the floating drilling season in the Beaufort was extended using ice-tolerant systems and new ice-breaking vessels; designs for sea floor installations to cope with ice scour were developed; in order to conduct safe floating drilling off Canada's East Coast, methods of detecting and towing icebergs were perfected; in the Arctic Islands, exploration drilling using floating ice platforms has been very successful. In addition, improved science has contributed to improved forecasting of weather, waves and ice as well as environmental impacts. In all the above areas Canada's engineers and scientists have achieved significant knowledge and world leadership.

On the other hand, it is only very recently that there has been a focus on lowering the cost of Frontier operations. Unfortunately, the recognition of this need has coincided with a massive withdrawal of research sponsorship by the industry, so the capabilities of Canada's technical community in this regard have not yet been tapped. One notable recent exception in which PERD played a role has been the development of spray ice platforms for exploration drilling in shallow water in the Arctic.

Initially, spray ice platforms were developed for relief-well drilling in case of a blow-out. In developing and understanding the performance of spray ice platforms for this purpose it became clear that they could probably be used for exploration drilling. Further research to examine their stability and to improve construction techniques was conducted (partly funded by PERD). This confirmed their suitability, and to date two wells have been drilled in Canadian waters (and two in U.S. waters with Canadian expertise). Spray ice platforms have halved the cost of conducting shallow-water exploration drilling in the Arctic. The technology has the potential to also lower the cost of production systems.

In summary, the key points relating to technology and science are as follows:

- Canada is a leader in the technology and science of oil and gas operations in the Arctic and ice-infested regions.

  In the past the main emphasis has been on enabling safe and environmentally sound operations.

  The potential to use Canadian expertise to lower costs has hardly been tapped. Where the need for lower costs has been addressed, significant progress has been made (e.g. spray ice platforms).

  Industry is used to the concept of collaborative research and the potential for increased industry/government research collaboration is significant. Especially if the research is focused on lowering costs.

Future Prospects based on Conventional Wisdom

Apart from the production and development plans mentioned earlier, activity in the Frontiers is at an all-time low. Exploration drilling has ground to a halt and there has been low interest in obtaining new leases.

A major factor in this low activity is the current drive in the industry to reduce costs and to only invest in projects which yield short-term returns. This strategy is driven by the general financial weakness of the industry which has also led to large staff reductions in the past few years.

At the same time, the major oil companies in Canada do see the need to replenish their current production and reserves, which are in decline. But, the current attitude is that, this will only be done if the economics are in-line with shareholders expectations. A major hurdle, even for those companies with financial strength, is to make the new Canadian supplies competitive whether they be from the Frontiers, the Oil Sands, or from enhanced recovery.

In the Mackenzie Delta/Beaufort Region, the prevailing industry view is that there are insufficient reserves discovered for an economically attractive development This is mainly because any developments are viewed as being by pipeline, and pipeline tariffs are kept reasonable by having sustained throughput for 25 years at the highest volume possible. So, for example, an 80,000

Barrel/day flow rate as proposed by Gulf for Amauligak would require recoverable reserves of about 600 million barrels in addition to the 350-400 million barrels discovered. The current industry strategy would appear to be one of preparing for additional exploration to start when the financial state of the industry will allow it It, appears that industry would start with onshore exploration first, in the hope of finding economic reserves based on lower-cost onshore fields.

Off the East Coast, the prevailing industry view is that some of the current discoveries such as Terra Nova can be economically developed using floating sys-sn Indeed: in other- offshore regions of the world, oilfields of less than 100 million barrels are being developed with floating production. At the same time, it must be noted that investors aren't exactly flocking to Newfoundland to initiate such projects. This could be because, although positive, the economics aren't as good as other opportunities; or it could be because of the industry's cash flow problems; or it could be that potential new investors see downside risks associated with the unique offshore environment and local political pressures. (Also, the 50% Canadian ownership rule may have discouraged foreign investors).

For natural gas, the current industry view is that Frontier gas will have to compete with southern gas, which is still considered plentiful especially in terms of undiscovered potential. This is reinforced by the most recent outlook on gas prices by EMR which " predicts only 60% parity with crude oil and a real price of $2.07/GJ[1] ($2.22/kcf[2]) in the year 2000 and only growing to $2.40/GJ ($2.58/kcf) in the year 2020 beyond. Given that remote Frontier gas projects need about $2.75/GJ ($2.95/kcf) to be economic, the general view is that these resources will stay undeveloped for several decades (although significant changes in fuel use could alter this outlook).

[1]GJ - Gigs Joule

[2]kcf - Thousand cubic feet

General Approach and Assumptions

The study approach has already been described earlier. It is in essence an examination of various Frontier development scenarios in terms of current reserves, economics, and sensitivity of the economics to changes, especially lower costs achieved through technology. Potential cost reduction initiatives are discussed in terms of specific technology and science thrusts and related R & D programs. After the Frontier scenarios have been examined, the technology and research opportunities are compiled in a common format and a discussion of their relative importance is given.

Development Scenarios

The first step in the analysis was to identify realistic development scenarios for the various frontier regions. These scenarios were based on the current and potential reserve base for a region, the experience of the authors and input form industry. The approach taken in considering each region was to iook at generic scenarios, and not at named potential developments. However, in some cases, cost data generated for specific developments has been used, Also, it is not difficult for the reader to see the similarity between some of the generic scenarios and actual discovered oil and gas fields..

The general scope of each scenario was established inorder to identify the associated capital and operating costs. Generally, the scope was based on inputs from a variety of sources including industry, the experience of the authors and past studies in the public domain. in some cases, where data was unavailable for a particular scenario, the scope and associated capital costs were established using NORCOST©, a Northern Regions Venture Cost Model developed by NORTH OF 60 ENGINEERING. The NORCOST© model establishes the scope and cost of facilities necessary to produce and transport oil and gas from the Frontier regions to southern markets.

in general, where a range of costs were available, the upper end of the range was used for the base-case economics. This was done to avoid the criticism of being overly-optimistic and hence reducing the credibility of the study.

Transportation Systems

Transportation systems were sized for each particular development scenario. Pipelines were sized based on hydraulic considerations which are a function of throughput, operating pressure and pump or compressor station spacing. Associated development and operating costs were established based on input from industry, technical experts, and the NORCOST© model described above.

Tanker transportation costs and tariffs were based on a lOOK DWT class tanker. The number of tankers required for a particular scenario was based on production rates and transit times to market. Tanker cost were based on past studies and input from technical experts.

Economic Analysis

The economic viability of each development scenario was then calculated using a model developed for Frontier regions by NORTH OF 60 ENGINEERING. The computer model calculates a venture's rate of return on an after tax, after royalty basis.

The required information, includes development costs, production profiles, operating costs, production price forecasts, inflation and tax rate assumptions. Capital and operating costs for each development scenario were established as described above. All costs were expressed in 1992 dollars and input into the models in real terms.

Production forecasts were developed for each scenario using a decline model developed by NORTH OF 60 ENGINEERING. The production profile is calculated based on a constant percentage decline. The initial production plateau is based on the reserve life index for the field which is an input variable. A 10 to 13 year life index was used for most of the development scenarios, based on the experience of the authors. The production decline commences after a certain percentage of the reserves have been produced. This value which is also an input variable, varied between 40 and 50% of the recoverable reserves.

A generic and relatively conservative price forecast was used for all scenarios. As the bulk of Canadian Crude is exported to the United States the price of oil was therefore tied to a $20 US/barrel flat (in reai terms) price forecast for West Texas Intermediate Oil in the Chicago market place. This assumption is in line with the views of most of the industry at this time and is also compatible with one of the cases in EMR's most recent forecast (e.g. 2020 Vision, 1933; with update through personal communication, 1992) Corresponding Canadian prices were then calculated for Edmonton and Portland, Maine.

'The price forecast that was used for natural gas is the one currently proposed by EMR. It is not very bullish because of the prediction that significant gas resources remain in Southern Canada and the Lower 48. Consequently, as gas prices rise, these additional resources can be exploited at relatively low cost (compared to remote gas). The price forecast predicts an average border price of $2.07/GJ ($2.22/kcf) by 2000 with a very modest real growth to $2.1 5/GJ ($2.30/kcf) by 2005.

With the exception of the east Coast development scenarios, the transportation costs are treated as tariffs. The pipeline and tankers are assumed to be independently owned and operated by a second party. A tariff model developed by NORTH OF 6 0 ENGINEERING calculates the revenue required to finance the debt, equity, operating costs and taxes for the transportation system. Tariffs are calculated in both real and nominal dollars. The tariffs in reai dollars are an input array in the economics model to calculate the effective field price.

Other fiscal assumptions used in the model indude the rate of inflation which was assumed to be 4% per year and the exchange rate which was assumed to be 0.80 $Cdn/$US. The royalties were calculated based on a CPRA royalty structure.

The economic parameters for the various development scenarios is summarized in figures throughout the report. The economics model determines the net cash flow for a development scenario on an after tax, after royalty basis. it calculates the present value of the net cash flow at a number of discount rates. The authors have used a 1 0% rate of return for comparative purposes throughout the report, however the reader may interpret the present value of a development scenario at other discount rates from the present value profile presented in the results.

The model also calculates the discounted cash flow rate of return (the discount rate at which the Net present Value is equal to $0.00), the Project Payout, which represents the number of years to recoup the initial investment, and the Cash Flow Productivity Index which is the present value net cash flow divided by the present value of the project investments. This indicator is useful for evaluating the various scenarios at **a specific** hurdle rate. Finally the model calculates a yearly earnings profile which are presented as a bar chart.

Sensitivity Analysis

The sensitivity **of** each development scenario to price (also volume), transportation tariffs, capital and operating costs, was also investigated. Each of these parameters was independently varied by 50% and the net present value at 10% calculated. The results of this analysis are presented as 'spider plots" along with the base case economics in Figures through out the report. The net present value does not necessarily follow a linear relationship due to the non linear nature of the Royalty structure.

Opportunities for Technology Uplift

The final step in the analysis was to identify opportunities for economic uplift through advances in technology that could possibly come from a focused R & D program. The authors have identified a number of technology and research opportunities for each development scenario. The merits of these opportunities which are compiled in a common format, are discussed and quantified in very general terms. Finally the economic uplift attributable to these opportunities is quantified for each scenario.

The Mackenzie Delta Beaufort Region

The Setting and Background

This region lies-approximately between the 69 degrees N and 71 degrees N latitudes at the mouth of the Mackenzie River. Pipeline distance to Edmonton is about 2300 km (although a 12" oil line already exists to Norman Wells which is within 600 km of the Mackenzie Delta.)

In addition to being remote, the region is subject to a harsh Arctic environment and this is the major reason for the high cost of operations (compared to the South). Physical environmental features which influence operations and add to costs are

- Winter darkness
- Low temperatures
- Permafrost and ground ice (both onshore and offshore)
- Numerous channels and lakes
- The presence of sea ice for 9 months of the year
- Extreme ice features up to 20-30 m thick
- Ice scour of the seafloor
- Weak seafloor
- Seafloor hazards such as shallow gas and hydrates

Despite the above hazards and constraints, industry has developed the capabilities to safely conduct exploratory drilling through permafrost and offshore (out to about 30 m water depth using year-round fixed platforms, and deeper, using drillships during the summer and early winter). There has also been extensive study and engineering of development systems including trunk pipelines to the south, gathering systems, producing wells through permafrost, foundations on permafrost, offshore platforms to resist ice, offshore pipelines to cope with ice scour and permafrost, as well as Arctic marine systems for construction and transportation of oil by tanker. (e.g. see **Beaufort** Sea - Mackenzie Delta Environmental Impact Statement; Dome et **al,** 1982).

In fact, over to 200 wells have been drilled in the region including about 90 offshore. Some of the deeper offshore wells have cost up to $100 million to drill, whereas, onshore wells can now be drilled for about $8 **million.**

Significant discoveries are shown on the map, **Figure** 6.

BEAUFORT SEA/ **MACKENZIE** DELTA
SIGNIFICANT DISCOVERIES

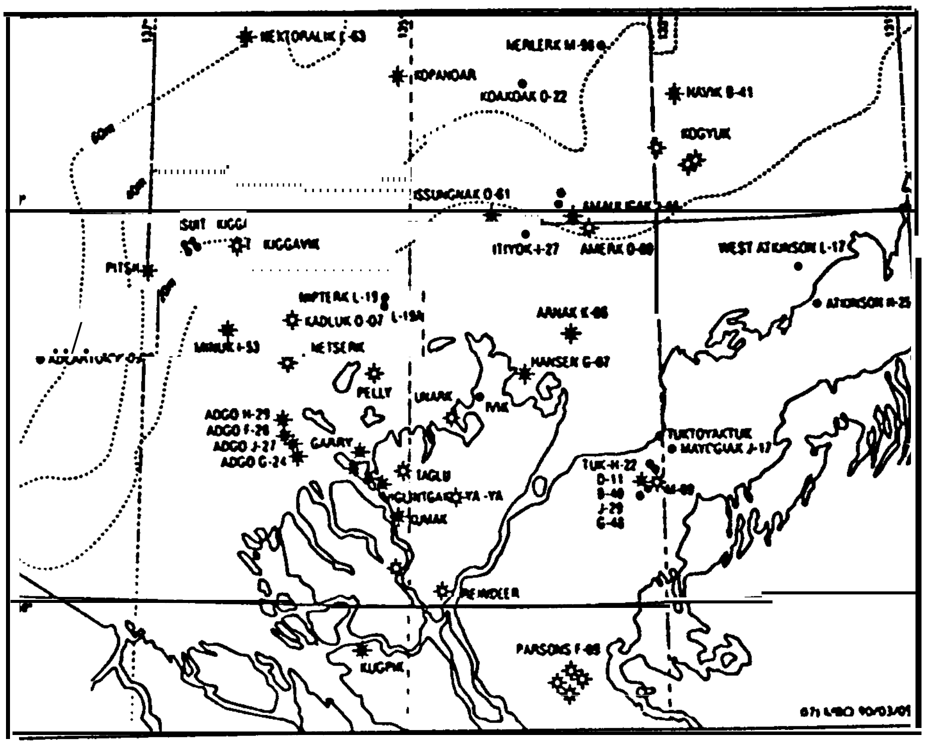


Figure 6 (Dingwall, 1990)

Estimated discoveries to date and potential are given in Table **6.** The largest **oilfield** discovered is **Amauligak,** which lies offshore in about 30 m of water. it is estimated to contain about 350 **million** barrels of recoverable oil and about 2.0 Tcf of gas.

The largest discovered gas field is **Taglu** in the Mackenzie Delta. it is estimated to contain about 3.0 Tcf of gas and about 30 million barrels of liquids. Other onshore and offshore gas fields give a development potential of about 12 **Tcf.**

Mackenzie Delta / Beaufort Sea
Discovered and Potentall Reserves (GSC,1988)

REGION	Oil (Billion Barrels)		Gas (Tcf)	
	Discovered	Potential	Discovered	Potential
Onshore - Shallow Offshore	022.0.22	0.22-1.18	6.6 - 8.3	9.4- 19.7
Offshore Delta	0.2-1.0	1.0-1.3	3.0- 4.0	12-15
West Beaufort	0.05- 0.35	1.35-2.15	·	12
Deep Offshore	02-0.4	0.2-1.2	0.4.0.8	13 - 19
Total	127-2.01	4.07- 5.s3	10.0 -13.1 -	4e.4 -25.7

Table 6

As discussed earlier, production plans for both gas and oil have been developed, but have been shelved because of poor economics.

Typical development scenarios with costs and economics will now be reviewed in some detail.

Oil Development Scenarios

A decade ago, the Beaufort EIS (Dome et al, 1982) considered oil production mainly from offshore fields at rates up to 700,000 barrels per day (although the discoveries to sustain such a rate had not been made, and have not to date!). In recent years with the discovery of Amauligak and some small but promising onshore discoveries, the industry has usually considered two distinct scenarios for Beaufort Oil.

One is an offshore development based on Amauligak producing about 80,000 barrels/day transported via a 16 inch (or bigger) pipeline up the Mackenzie Valley to Alberta. As will be shown later in the generic case, such a scenario is very close to being economic, if the pipeline tariff is based on the pipeline running full at 80,000 **BPD** for a 20 year period. But, the current **reserves** at **Amauligak** are not sufficient to achieve **this**. Even when some of the better smaller fields are 'added, there is still a shortfall. **The** conventional wisdom for **Amauligak** is that it is stalled until more reserves are discovered.

The other scenario for **Beaufort** Oil is to consider only **the** onshore (and very shallow offshore). Current onshore discoveries do total about 120 million barrels, but in relatively small fields. **A scenario** often looked at is an extension of the Norman Wells pipeline to the Mackenzie Delta to produce onshore oil at about 25,000 BPD from a yet-to-be discovered onshore field of 100- 150 million barrels. **As** will be discussed shortly, this scenario can be economic if certain cost savings are achieved and the pipeline extension can be kept running full for **a** 20-25 year period. Currently, there are insufficient onshore reserves discovered to achieve this **sustained** production.

To provide **additional** insights on **Beaufort** oil development economics and their sensitivities, we will **now** examine generic oil scenarios in detail.

Onshore Oil

A generic case of a 100 million barrel (recoverable) **oilfield** has been chosen. No such **oilfield** has yet been discovered, but it is understood from personal communications **with** the industry that geophysical and geological interpretations indicate that such-sized fields (and larger) are a possibility onshore, and future drilling will be aimed at such targets. Also, this generic case helps to put in perspective the economics associated with the smaller onshore fields discovered to date (which may in **total** equal slightly more than 100 million barrels, but are dispersed over several 100 km and would be less economic to develop in total than this generic case).

Costs for the surface facilities and development drilling in the **base-case** are derived from the highest values obtained in discussions **with** industry. Based on the authors' experience we believe the costs are quite conservative and could probably be reduced even without technology uplift. The pipeline tariff which is given in Figure 7 is also based on the **high-end** of the range of costs to build the extension from N. Wells to the Mackenzie Delta.

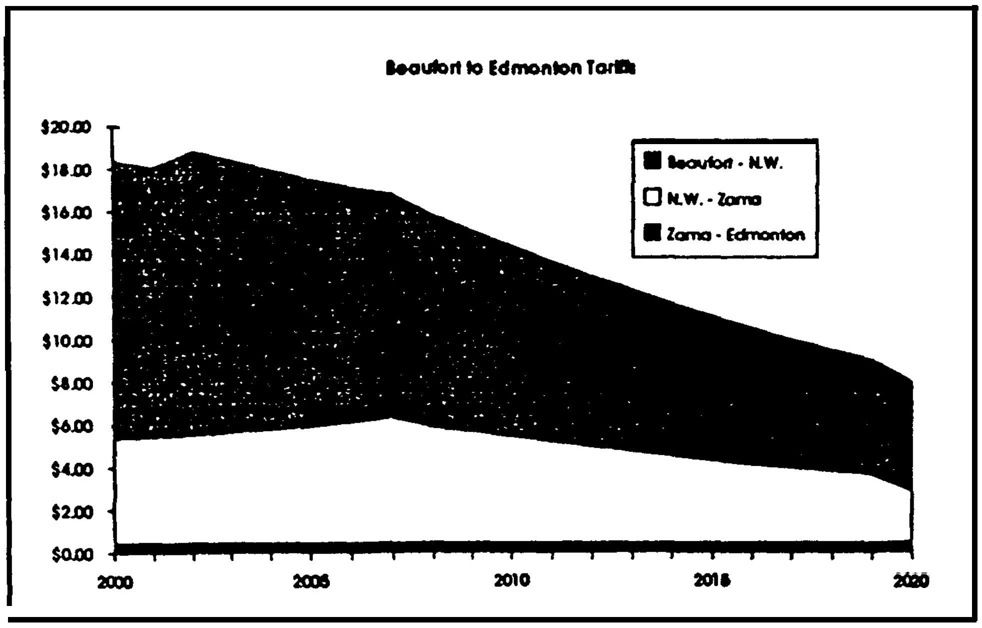


Figure 7

As a result of these rather conservative cost assumptions, combined with the flat price outlook, the base-case **economics** are not attractive. In fact, this case regardless of hurdle rate of return is never economic, and the net present value at 10% rate of return is a negative $200 million. However, sensitivities relating to price and costs are given in **Figure** 8 What these show is that an oil price of $26 U.S. is needed to yield a 10% rate of return. On the other hand, the sensitivities **also** show that **a 35%** reduction in capital costs and transportation costs will likely create an economic **project**, even at a flat $20 US. oil price. Given the **conservative** values assigned to costs, it is very likely that such cost reductions are within reach, if **smart** engineering, together **with** technology improvements, based on focused R & D, are implemented. (These will be discussed **later**).

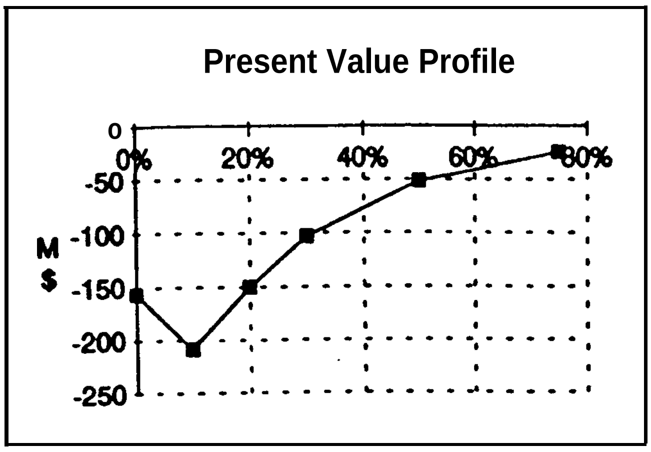
The big drawback to this case is that of needing to **maintain** a flow rate in the pipeline of 25,000 **Bbl/day** over 20 - 25 years. To achieve this, more than one 100 **MBbl** pool is needed (**in** fact, total reserves of over 300 **MBbls** are required). So, regardless of improvements in development technology and costs, the onshore oil scenario requires additional exploration beyond the discovery of the first nominal 100 million **Bbl** field. This begs the question of whether technology should be focused on lowering exploration costs in order to improve the chances of finding the required reserves? This could be just as high a priority for **the** onshore as reducing development costs, at least in the short-term (Lever, 1992).

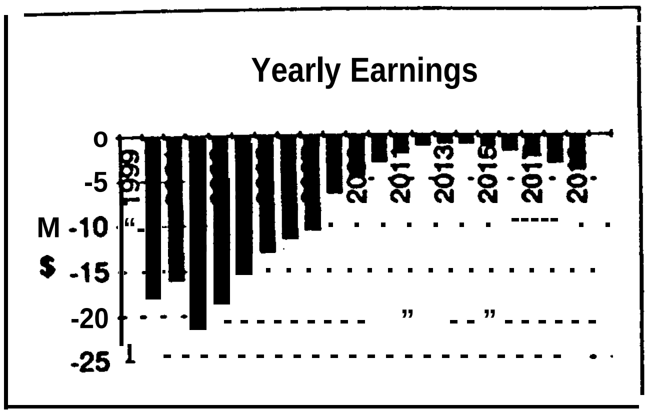
Beaufort Onshore 011-100 MBbl - 25,000 B/D

Investment	M$
Exploration	15.00
Development Drilling	285.00
Production Facilities	200.00
Gas Gath. & Processing	0.00
Total:	500.00

Net Present Value	M$
o%	-157
10%	-208
20%	-150
30%	-103
50%	-51
75%	-25

Net Present Value at 10%	($208)
Discounted Cash Flow Return	0%
project Payout (Years)	.
Cash flow Productivity Index	-0.57





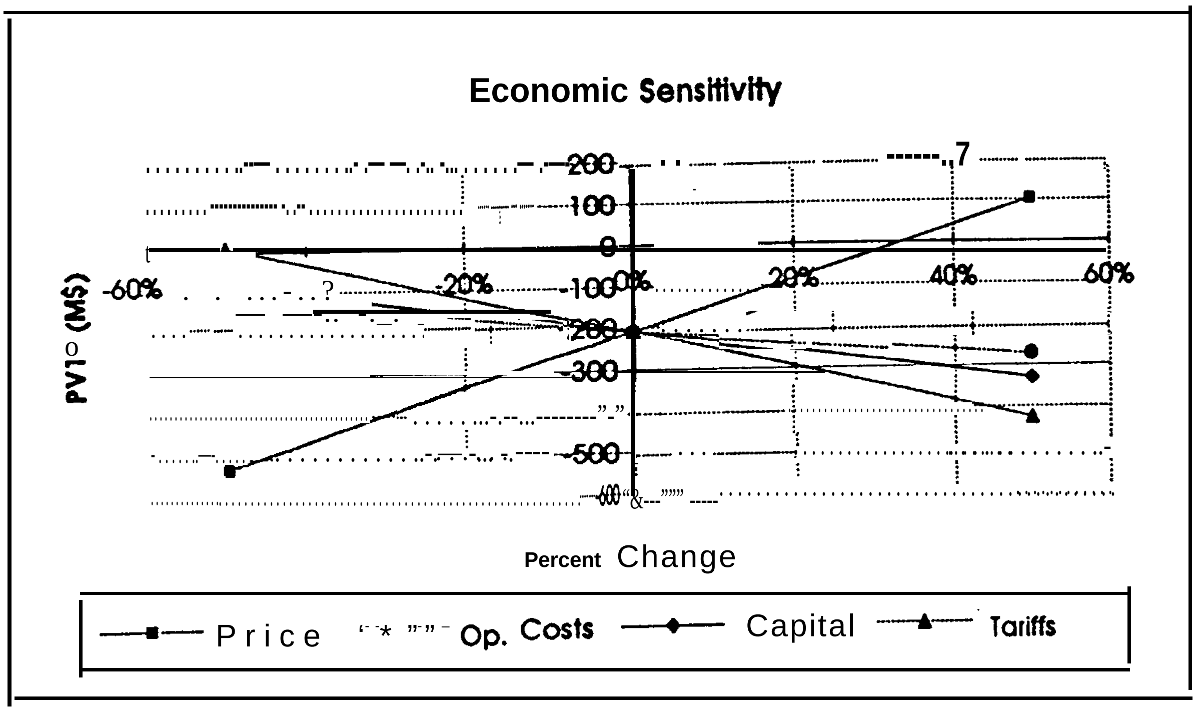


Figure 8

Offshore Oil - Large Development

A generic case of an offshore oilfield with recoverable reserves of 350 MBbls has been chosen. This, of course, is very similar to the Amauligak case, in fact, the cost data generated by industry for Amauligak (Gaida, 1992) has been used to develop the base-case economics. Amauligak is the largest oilfield discovered and delineated in the Beaufort Sea to date. Other notable, but smaller, discoveries with their estimated potential and water depths are shown in the following table.

Various Beaufort Offshore Discoveries (in addition to Amauligak)

Field	Estimated Potential (MBbls)	Water Depth (m)
Issunguak	120	19
Tarsiut	100	22
Pitsiulak	50	30
Havik	40	25
Isserk	30	15
Nipterk	30	7
Adlartok	100?	150
Total	470	

Table 7

The above table suggests that the economics of a generic 350 MBbl pool represents the best case for offshore discoveries to date; i.e. the economics of the other pools as stand-alone developments will likely be poorer. On the other hand, as will be discussed, the pipeline tariff model for this case, as shown in Figure 9, assumes the pipeline can be run full at 60,000 Bbl/day for 20 years. This requires at least another 600 MBbls of oil be made available to the pipeline during its operational life. As the tariff decreases with time as shown in Figure 9, and as infrastructure improves, it may be possible that some of the smaller fields listed can be produced economically and would make-up the 600 MBbls needed (onshore fields could also contribute). However, the general view in the industry is that additional large fields need to be found.

Turning now to the 350 MBbl generic field in 30 m of water, this development assumes a peak production rate of 80,000 Bbls/day and will require a capital investment (not including the onshore trunk pipeline) of about $2.2 billion. The percentage make-up of this investment is given in Table 8 below.

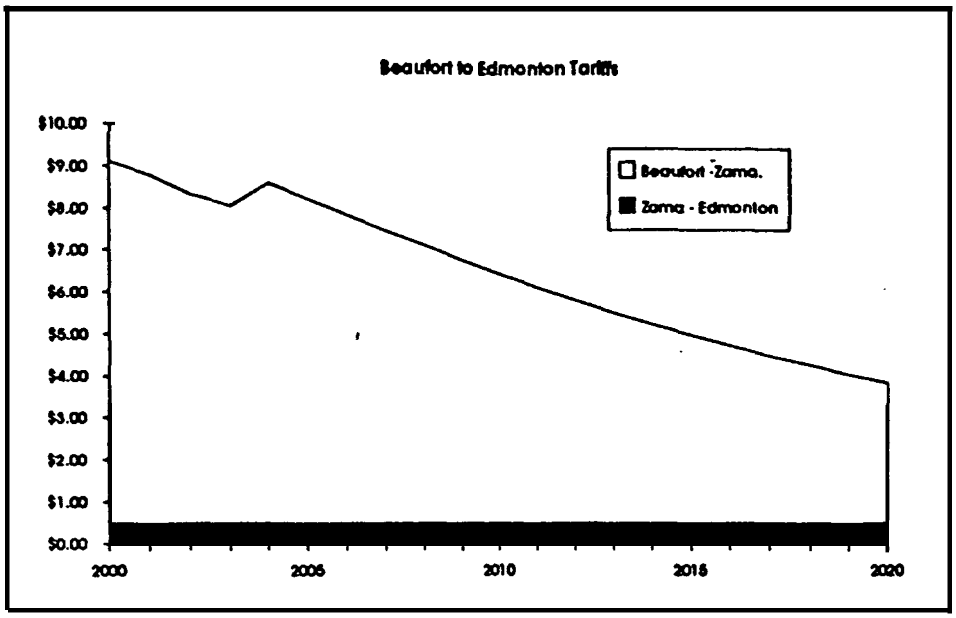


Figure 9

Generic Beaufort Offshore Development Costs

Project Component	% of total investment
Offshore pipeline	12
Platform and Topsides	45
Development Wells	27
Northern Base Camp	3
Engineering, etc.	13
Total	100

Table 8

Platform and topsides (processing **equipment,** utilities, accommodation, etc.) make-up the biggest **proportion** of the total investment Various platform types have been considered for this kind of development **(Stamberg,** 1988). The costs used in this analysis are for a caisson retained island with the topsides built on barges and **incorporated** into the **island. A** massive structure is required to resist the ice loads both global and **local,** which, because of uncertainties, have generally been specified very **conservatively.**

Ice also affects the offshore pipeline **which has** to be laid in a trench so that it is protected against ice scour. This feature adds significant cost, especially as the cost **estimate** assumes a **two-**summer construction period (which in turn **requires a trench with** shallow side slopes to avoid instabilities due to summer **storms, and** hence more dredging).

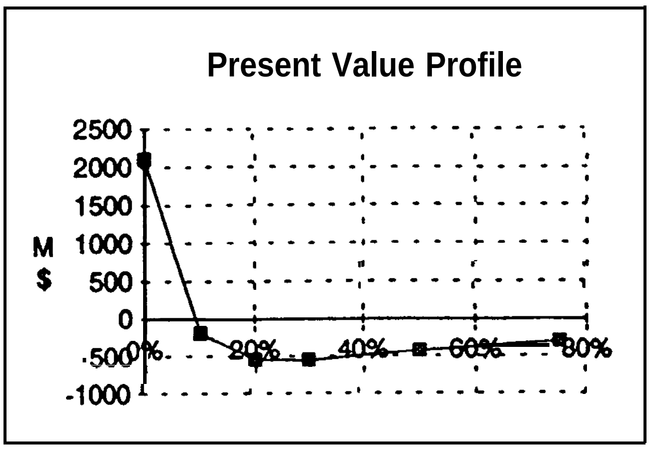
Other assumptions for the base case are listed in Figure 10, as is the economic summary. This **scenario** has a rate of return of 80A, and a net present value of -$199 million at a **10%** hurdle rate. Sensitivities **on** costs and price are also given in the Table, and these show that an oil price of $22 U.S. is needed to yield a 10% return. Alternatively, if capital costs can be reduced by about **17%,** the yield is also 10%. This is the challenge for technology improvements and doesn't seem an unreasonable target. Reductions in the pipeline tariff would also help. **As** shown, if the pipeline tariff can be reduced by 30%, this would also **lead** to a rate of return of 10%. Such a reduction might be achieved through improved pipeline technology and **construction** techniques, as will be discussed later. However, it should be remembered that this case still assumes that additional fields in the Beaufort are brought into production, in order to **maintain** a full pipeline **and** minimum tariff. This requires additional discoveries possibly combined with development of already discovered smaller fields (which might be economic as the pipeline tariff declines).

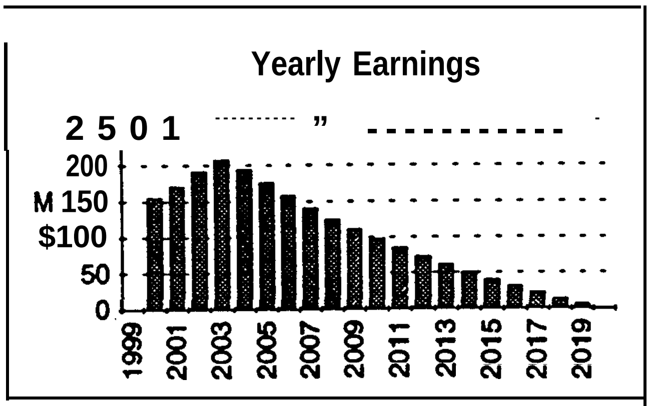
Beaufort Offshore Oil -350 MBbl -80,000 B/D

Investment	MS
Exploration	0.00
Development Drilling	800.00
Production Facilities	1590.00
Gas Gath. & Processing	0.00
Total:	2190.00

Net Present Value	M$
0%	2104
10%	-199
20%	-555
30%	-583
50%	-438
75%	-312

Net Present Value at 10%	($199)
Discounted Cash Flow Return	8%
Project Payout (Years)	13
Cash Flow Productivity Index	-0.11





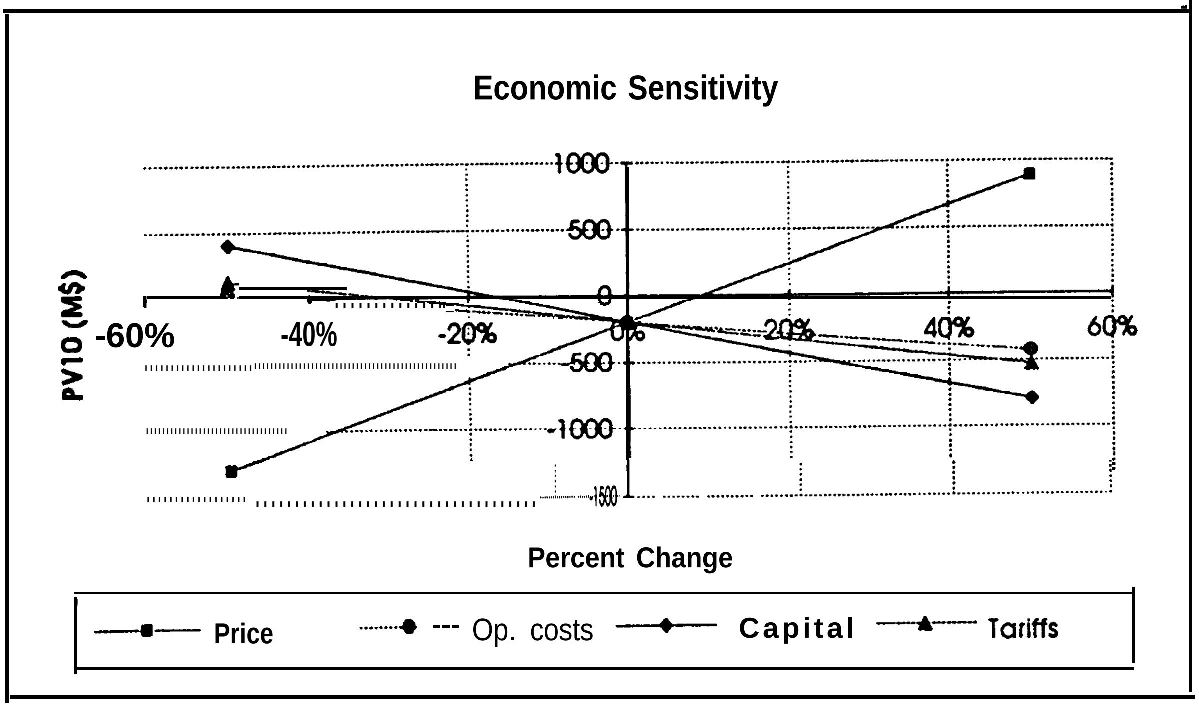


Figure 10

Offshore Oil - Marine Transportation

Recognizing how the use of a pipeline requires the need for additional volumes, in order to be economic, it is appropriate to consider an alternative transportation system, i.e. the use of ice breaking tankers. Clearly the use of tankers in ice-infested waters is an environmental concern, especially after the Valdez incident. However, it should be noted that most of the world's oil is moved by tanker. Also, several Arctic tanker production scenarios are currently being examined for Western Siberia, where it is planned to move onshore oil to market via tankers plying the Petchora and Barents Sea.

In the early 1980's a big debate raged over tankers versus pipelines for Beaufort oil. Dome Petroleum was a strong advocate of tankers, and Table 9 is reproduced from one of their publications at the time (Dome Petroleum Ltd., 1982). Also, at that time, Dome quoted a tanker tariff of about $8 for transport to Montreal via the N.W. Passage, see Figure 11. Up to date estimates for Arctic year-round tanker transport are not available. Bent Horn oil is moved to Montreal using the M.V. Arctic in the summer for about $6 per barrel (Hewitt, 1992). In any case, by examining the previous pipeline scenario, it can be deduced that an average tariff of about $5-$6 per barrel will create an economic (10% R. O. R.) project. A tanker case will not require the offshore pipeline, with an associated saving of about $260 million. if this cost is allocated to storage (about one million barrels is needed to maintain production between tanker offloading), and an average tariff of about $9/B is assumed, then, the tanker case requires an oil price of about $24 U.S. to be economic.. The major advantage of the tanker scenario is that additional reserves may not be needed because the tankers could be used for other trade as production rates diminished, and fewer tanker offloads were required.

Clearly the above analysis is quite approximate and need some refinement. Arctic vessel experts with whom the authors have consulted, say that there are no technological barriers to such a scenario and that improvements can be made to the design concepts of a decade ago which could lead to lower costs. In addition, any cost reductions relating to the platform itself would enhance this scenario as well as the previous one (and will be needed to create a robust project).

Tankers vs Pipelines

RELATIVE MERITS OF ALTERNATIVES
FOR THE TRANSPORTATION OF BEAUFORT SEA HYDROCARBONS

ADVANTAGES

TANKERS

- SYSTEM CAN BE JUSTIFIED AT THE EARLIEST POSSIBLE OATS
- LOWER COSTS ANO GRADUAL COST ● UILO-UP ALLOWS FINANCING TO SE ASSISTED ● Y CASH FLOW
- COST AND ECONOMIC ADVANTAGES AT LOW-MEDIUM THROUGHPUT LEVELS
- FLEXIBLE SYSTEM, CAN REACT QUICKLY TO MARKET CHANGES
- LONO TERM BENEFITS OF SHIP CONSTRUCTION, MAINTENANCE ANO REPAIR
- S00S1S ARCTIC EXPLORATION
- NEW CANADIAN TECHNOLOGY
- CANADIAN PRESENCE IN THE ARCTIC
- OFFERS EXPORT OPPORTUNITIES
- RESUPPLY OPPORTUNITIES

PIPELINES

- DEVELOPED TECHNOLOGY
- PROVEN SAFETY RECORD
- ECONOMIC ADVANTAGES AT HIGH THROUGHPUT LEVELS
- SHORT-TERM BENEFITS DURING PIPELINE CONSTRUCTION
- ● OOSTS N.W.T. EXPLORATION
- PROVIDES NORTHERN REVENUE
- LOWER OPERATING COSTS

DISADVANTAGES

TANKERS

- MARINE ENVIRONMENTAL CONSIDERATIONS
- SYSTEM IS LESS ENERGY EFFICIENT
- NOT COMPLETELY PROVEN

PIPELINES

- HIGH CAPITAL COST. DIFFICULT TO FINANCE
- PRONE TO COST OVERRUNS
- ECONOMICALLY SIZED UNES CANNOT SE QUICKLY JUSTIFIED (SUBSTANTIAL RESERVES REQUIRED)
- REDUCED GOVERNMENT ROYALTIES
- NO SHIPBUILDING INCENTIVES
- ONSHORE ENVIRONMENTAL CONSIDERATIONS

(

Table 9 (Dome Petroleum 1982)

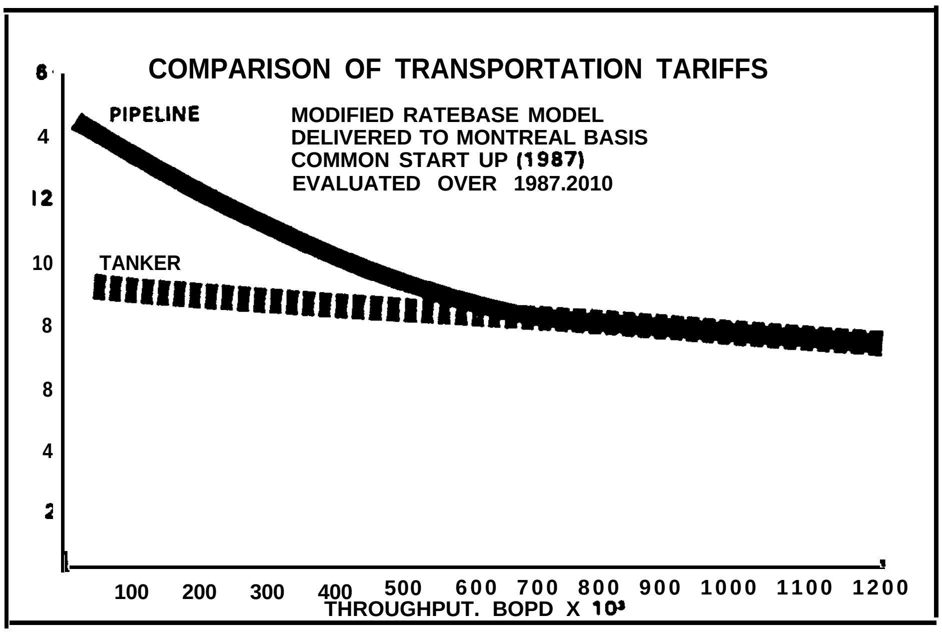


Figure 11 (Dome Petroleum, 1982)

It should also be noted that there are a number of other scenarios which could involve marine transportation including seasonal production. These will be discussed in the following section.

Small Offshore and Seasonal Developments

Clearly the scenarios discussed to date (except perhaps the tanker case) will all require additional oil reserves to be discovered, in order to be economic. It is also of interest to note that the 350 MBbl offshore case appears to have more robust economics than the 100 MBbl onshore case. This leads to the thought of examining small offshore oil developments which either make use of the Norman Wells line or tankers on a year-round or seasonal basis.

In the pipeline scenario, the 350 MBbl offshore pool is produced at 35,000 Bbl/day. The total production of 35,000 Bbl/day helps to significantly reduce the tariff for the Norman Wells extension over the previously examined onshore case. It also ensures that the existing pipeline from the south to Norman Wells will run full for decades to come. In this scenario, it would have to be upgraded to carry about 45,000-50,000 Bbls/day depending on the production rate decline of the Norman Wells field.

Capital costs for this case assume that an existing drilling caisson the size of the Molikpaq can initially be used as a production platform. It may be necessary to provide additional ice resistance and some allowance has been made for this. It is also recognized that all the reservoir may not be reached from a small platform with a limited well capability. Therefore, a second small platform for $150 million is added. In the case examined, this is added as an initial investment, however, in an optimized project the second platform might be delayed for several years. Figure 12 gives the capital cost assumptions for this case. The large amount for development drilling is spread over the life of the project as different parts of the reservoir are accessed. It should be noted that in this scenario, the production life of the offshore field is well over 20 years and decline doesn't start until year fifteen. The economics for this scenario are also shown in Figure 12. The project yields about 8% return and, therefore, the sensitivities indicate that an oil price of about $21.00 U. S./Bbl will make the scenario economic with a 1070 return. Alternatively, if the transportation tariff (i.e. the pipeline cost) is reduced by about 20% and the capital costs by about 15%, the oil price required for 10% return reduces to $17.80 U. S./Bbl This appears to be quite a robust scenario which deserves further attention, as it will be given later in the report.

The thought of a smaller development could also be carried over into the tanker scenario. [f the production rate is chosen at about 30 - 35,000 Bbls/day, then the offshore platform could be an existing caisson, as was discussed above, with a second small platform added later. Storage would be needed and it is assumed that it can be provided for the same cost as the offshore pipeline, i.e. $150 M. Tanker and storage size would be chosen in conjunction with transit time, so that production could be maintained relatively constant. It is assumed that the tanker tariff averages about $9/Bbl which is probably conservative. Even so, as shown in Figure 13, the case appears to have attractive economics (i.e. a return of 14~0).

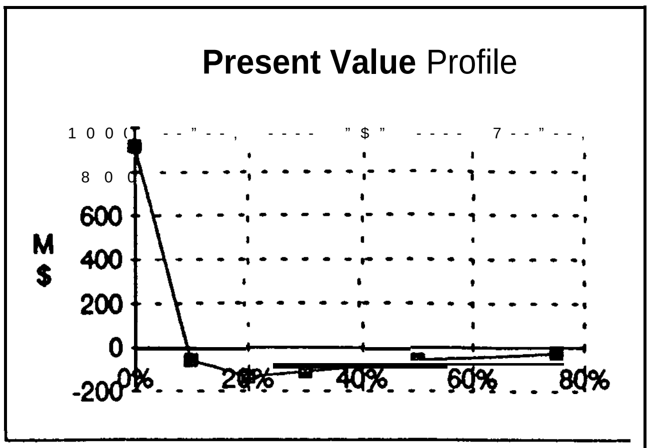
An even simpler version of this case would be to use an existing ice breaking carrier, but not year round. Such a case has been examined, which assumes a capital investmentof$120 million and a total tariff of $6/Bbl. Production rate is 30,000 Bbl/day for about 90 days for an effective daily rate on an annual basis of 7500 Bbls/day. Operating costs include a lease cost for the caisson of $5 million/year. Gas is used for fuel, but excess beyond that is flared. Using the above assumptions, the rate of return is calculated at 24%. Note that an eight year life was assumed recognizing that this is really an early production case and subsequently a larger or small year-round development would be implemented. The economic summary for this case is given in Figure 14.

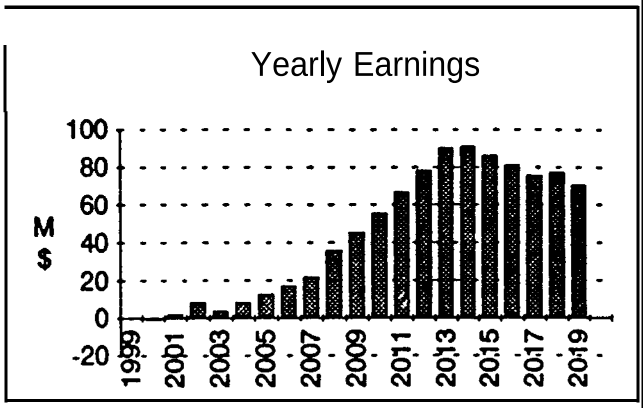
Beaufort Offshore Oil -350 MBbl -35,000 B/D - 12" Pipeline

Investment	M$
Exploration	0.00
Development Drilling	315.00
Production Facilities	475.00
Gas Gath. & Processing	0.00
Total:	790.00

Net Present Value	MS
0%	915
10%	-59
20%	-135
30%	-111
50%	-59
75%	-27

Net Present Value at 10%	($59)
Discounted Cash Flow Return	8%
Project Payout (Years)	18
Cash Flow Productivity Index	-0.11





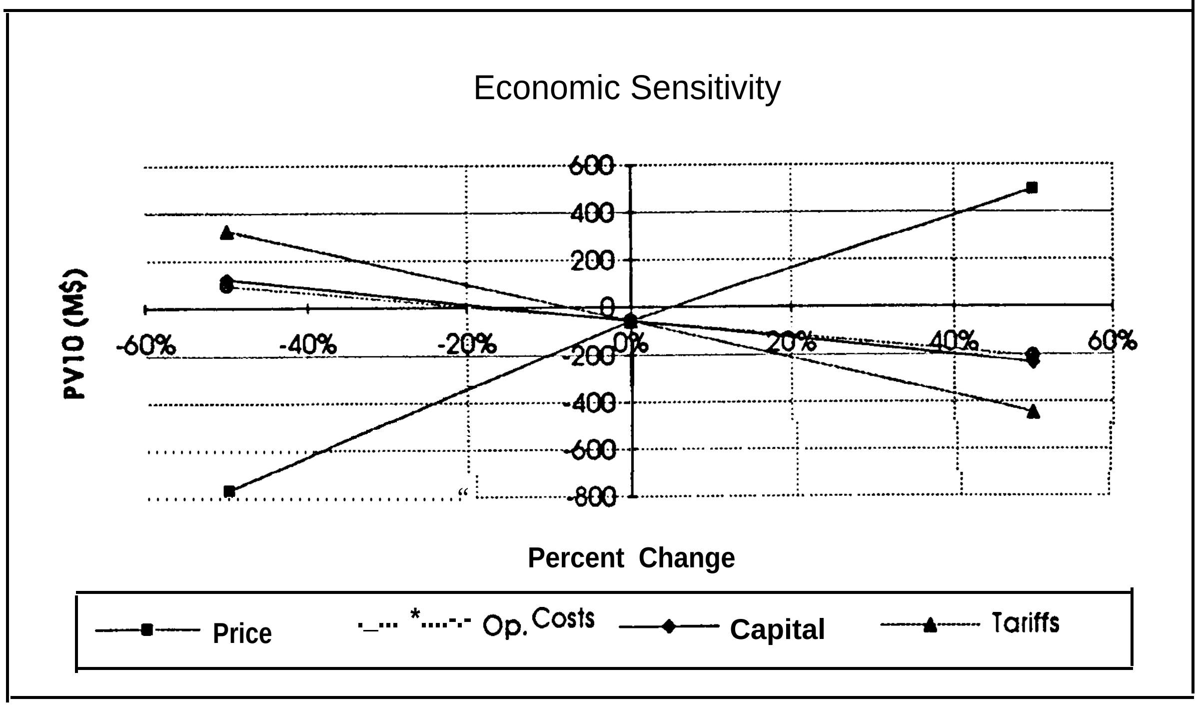
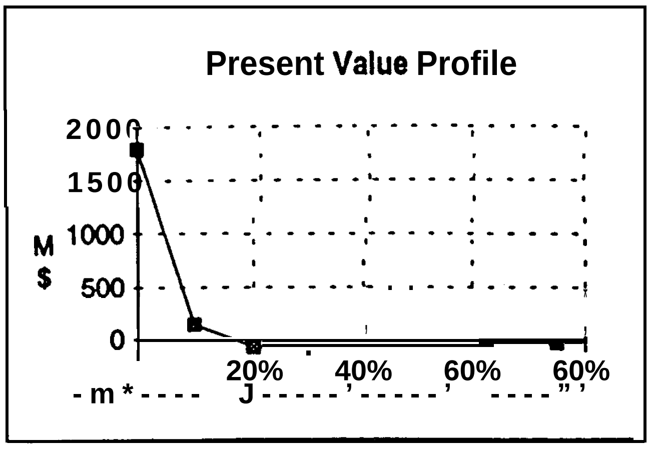


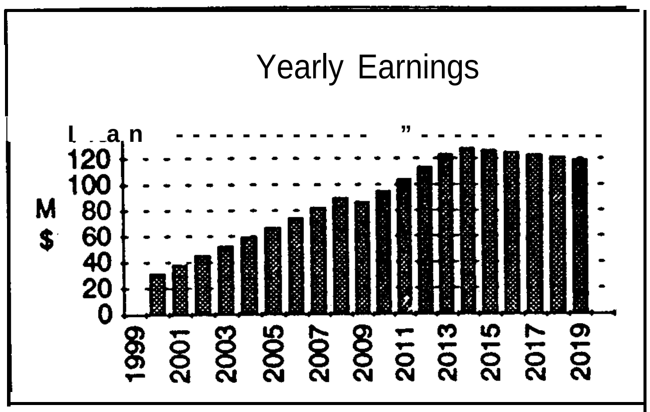
Figure 12

Beaufort Offshore Oil -350 MBbi -35,000 B/D - Tanker

Investment	M$
Exploration	0,00
Development Drilling	315.00
Production Facilities	475.00
Gas Gath. & Processing	0.00
Total:	790.00

Net Present Value	M$
0%	1792
10%	141
20%	-71
30%	-85
50%	-53
75%	-26





Net Present Value at 10%	$141
Discounted Cash Flow Return	14%
Project Payout (Years)	13
Cash Flow Productivity Index	0.27

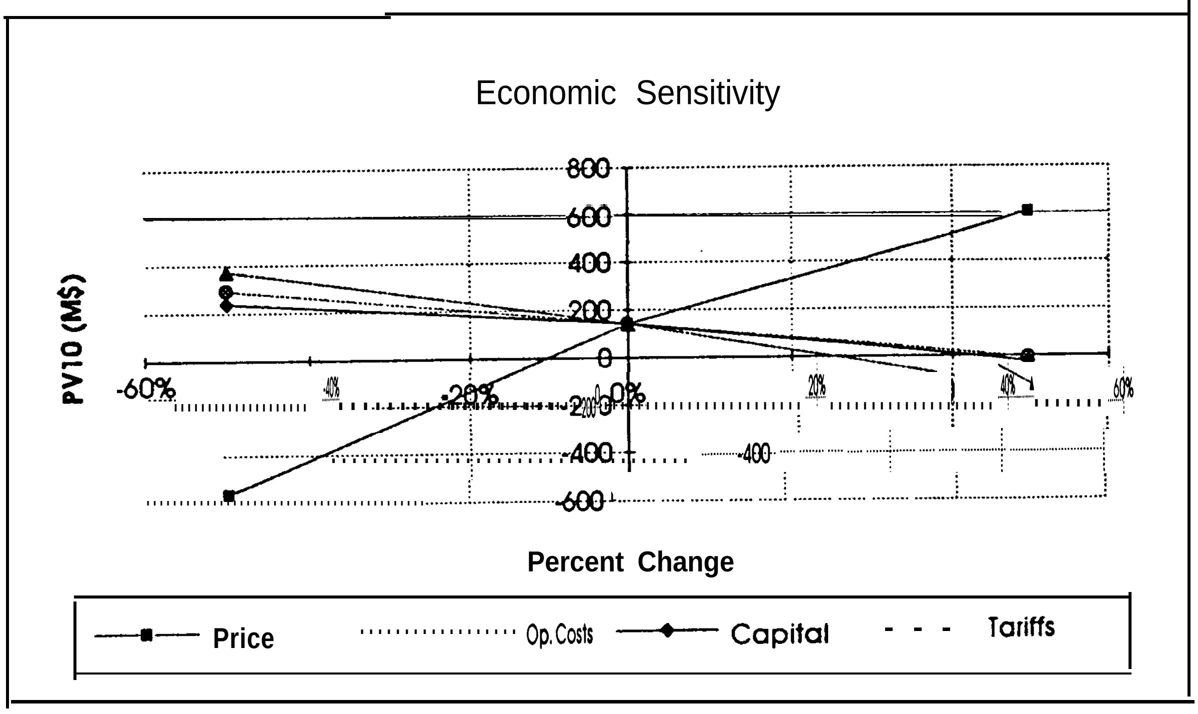


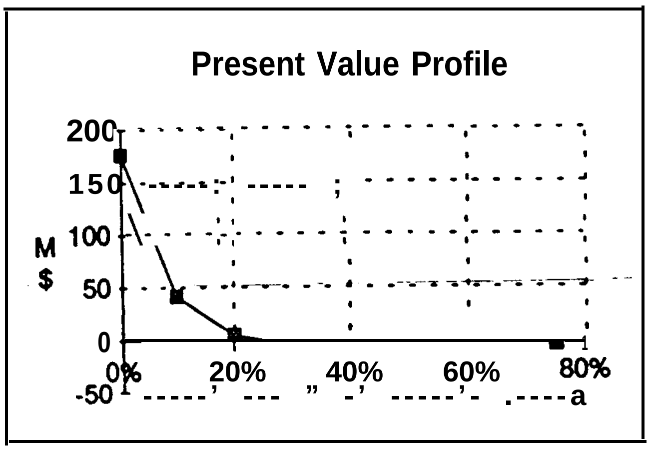
Figure 13

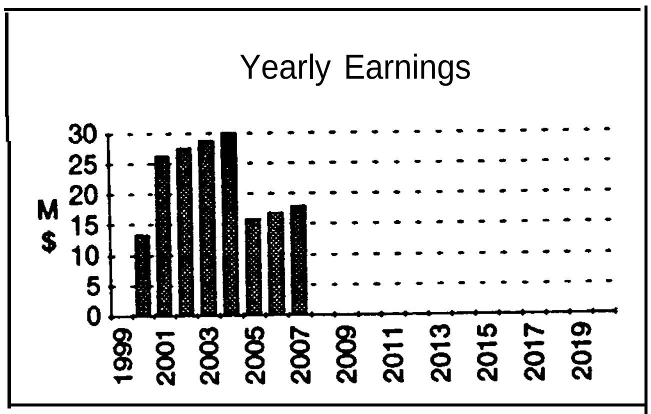
Beaufort Offshore 011-350 **MBbl - Seasonal Production - Tanker**

Investment	M$
Exploration	0.00
Development Drilling	50.00
Production Facilities	55.00
Gas Gath. & Processing	0.00
Total:	105.00

Net Present Value	M$
0%	176
1096	41
20%	5
30%	-4
50%	-6
75%	-3

Net Present Value at 10%	$41
Discounted Cash Flow Return	24%
Project Payout (Years)	10
Cash Flow Productivity Index	0.54





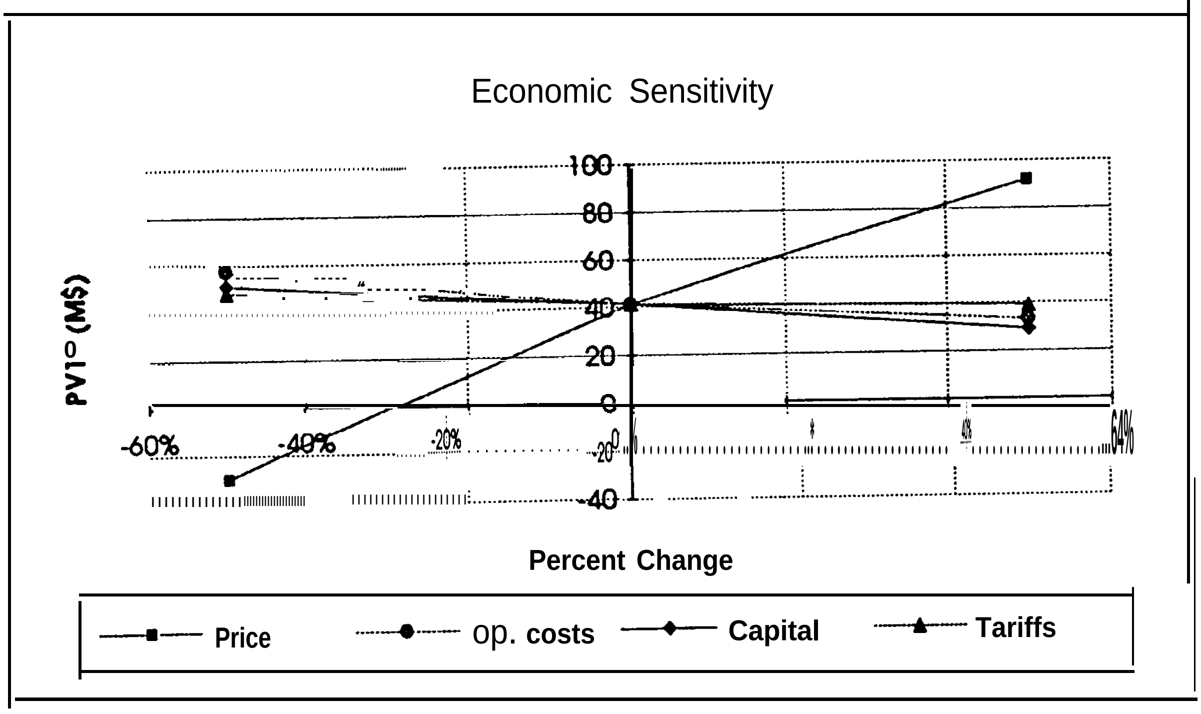


Figure 14

Economics Summary and Sensitivities

A comparison of all the scenarios examined in terms of the nominal U.S.$ price (West Texas) is given in Figure 15, from which a ready appreciation can be gained of their relative economics. Also shown is the oil price assuming technology can reduce capital and transportation costs through the research thrusts discussed later.

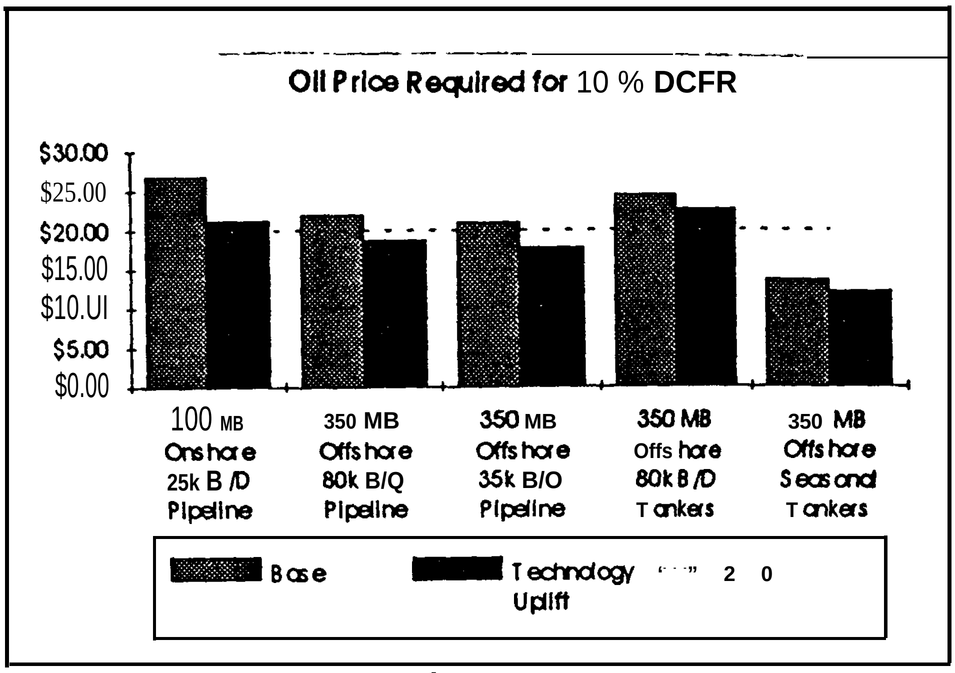


Figure 15

It is important to bear in mind in making the comparisons, that at least two scenarios require additional reserves to be discovered, otherwise, pipeline tariffs become unfavorable as production rates decline. The two scenarios which clearly have this requirement are the nominal 100 MBbl onshore field produced via pipeline at 25,000 Bbl/day and the 350 MBbl/day offshore field produced via a pipeline at 80,000 Bbl/day.

As already discussed, for the onshore case, total reserves of between 300 and 400 MBbls are needed and in fairly large fields i.e. 50- 150 MBbls depending on their location. To date, about 125 MBbls have been discovered onshore, and this could be as high as 200 MBbls if some shallow offshore fields are included. But, as already mentioned, the existing discoveries are generally less than 50 MBbls and certainly don't contain a lead-field for development. Industry will very likely be conducting additional onshore exploration in the next 5 year time-frame and the potential for discoveries in the 50-150 MBbl range are considered quite good. However, the pace of exploration will be determined by the financial state of the industry, competing exploration plays, and the cost of drilling. Progress has been made in reducing drilling costs but there is room for additional savings and these will be discussed later, For the offshore 80,000 Bbl/day case, additional reserves of about 600 MBbls are needed, with the existing Amauligak discovery as the lead field. The pace of exploration in the offshore is governed by the same factors as onshore, except that the cost of an offshore well can be up to $50 million depending on water depth, Lower exploration costs would, therefore, also help this scenario.

Whether the year-round tanker scenarios have the same problem of additional reserves depends largely on whether tankers can be leased from a third-party, who can deploy them for other trade as the production rate declines. It could also depend on the size and number of tankers and storage capacity. A more detailed study is needed before the sensitivity of these cases to reserves can be assessed.

Aside from the tanker cases there is one pipeline scenario which does not require significant additional reserves to be discovered, although it would be enhanced by such discoveries. This is to make use of an extension to the Norman Wells line to produce the offshore 350 MBbl pool at 35,000 Bbl/day. As a stand-alone project, it can be economic if capital costs can be kept at $600 M or less and pipeline tariff reduced by 25%. These targets are considered plausible if innovation and focused R &, D are applied to achieve technology improvements and lower-costs. It is also of interest to note that this case could be preceded by a seasonal tanker development which could yield early cash flow.

Technology Improvements and Research Opportunities

To provide an initial focus for this discussion, the scenario based on small-scale offshore development of a 350 MBbl offshore field will be discussed first. This is useful because the scenario contains elements common to the others, and, therefore, ideas and research discussed for this case are also common.

The basic elements of the scenario are itemized in Table 10. For each element the base-case costs are displayed as well as the target costs for economic enhancement. The target costs for each element are somewhat arbitrary and based on judgement of what is

Research Thrusts for Small Offshore Beaufort Development

Scenario:	**Beaufort** Offshore: 350 MB Field: Small Pipeline Development
Prize:	• Northern Oil Development@ 35,000 B/D (Value/Year if Displacing Imported Crude is $320 M) • Regional Development - Technology Development

Element	Base Case Cost ($M)	Target Cost Technology Uplift ($M)	Comments and Ideas for Innovation & Research Thrusts
Offshore Platform (Structure Only)	225	180	- Adaptation of existing caissons - assess risks and appropriate ice loads within probabilistic frame work - focus on uncertainties. - Develop industry consensus on ice loads on production platforms. Investigate use of spray barriers and underwater berms to protect a minimum structure - assess response to ice and waves. - Conduct a study on extreme ice features and their management.
Offshore Platform - Prod Equipment	100	90	- Focused study on construction optimization including application of latest technology end cost data from other offshore and remote areas. This would further identify specific Opportunities.
Development Drilling and Completions	315 Over Life of Project	230	- Use horizontal drilling to minimize number of wells to access the reservoir. - Optimized design for slant holes through permafrost. - Improved methods of dealing with permafrost strains on casing.
Offshore Pipeline	150	100	- Build in one summer and one winter season. Extend working season off the ice using spray ice platforms. - Optimize ploughing and dredging. Assess burial depths vs risk.
Totals	790	600	(-25%)
Pipeline Tariff	$15/Bbl (initial) $11/Bbl (final)	25% Reduction	See Table 11 for ideas on capital cost reduction of pipeline extension: Norman Wells to Beaufort

Table 10

achievable, the intent, however, is for the total capital cost to be reduced by the amount necessary to enhance the economics to an acceptable level. In some cases the required research thrusts may not be to achieve significant cost reduction, but to ensure environmental acceptability and safety.

In this scenario, the most likely areas for significant cost savings would be the offshore pipeline and the production wells. Ideas for achieving cost reductions are mentioned. However, the "ideas list" is undoubtedly incomplete and will benefit from the input of other experts.

The offshore platform(s) for this scenario could be existing caissons suitably adapted, or a new minimum structure with ice protection. In both cases focused R & D will be needed on ice loads and defensive systems such as spray ice barriers and underwater berms. The recent review of ice research priorities for PERD Task 6 should be consulted for more details of ice force research needs (Masterson and Wright, 1992).

The small offshore development case can benefit significantly from a lower pipeline tariff, a target reduction should be 25%. Ideas for achieving this are itemized in Table 11. The biggest leverage element is to look for innovative methods of pipeline installation and construction. These could include striving for a one-winter only construction period by extending the construction season through the use of techniques such as spray ice. Also, improved ditching techniques and detection of adverse terrain should be addressed. Other ideas and research thrusts are itemized in the Table.

Reduction in the pipeline tariff is also important to the Beaufort Onshore scenario; other elements relating to this scenario are itemized in Table 12. With respect to development costs, there are really only two main elements; the production facilities and gathering lines, and the production wells. Based on comparisons with Alaska, it is believed that the base-case costs are quite conservative. So a first step in seeking innovative methods and improved technology is to assess the learnings from Alaska and adapt them to the Mackenzie Delta. This applies both to facilities and wells. The well design needs to be optimized for the specific permafrost stratigraphy of the Delta, and low-cost methods of dealing with casing downdrag due to permafrost degradation assessed. (Considerable work has already been done on this topic,

Research Thrusts for Beaufort Pipelines

Scenario:	12 Inch Diameter Pipeline, Norman Wells to Mackenzie Delta		
Prize:	. Trigger Economic Northern Oil Development (35,000 B/D) • Keeps Norman Wells Line Running Full (Hence Lower Costs for Norman Wells Production)		
Element	**Range of Base Case Costs ($M)**	**Range of Target Costa Technology Uplift ($M)**	**Comments and Ideas for Innovation & Research Thrusts**
Pipeline Materials	100-130	90-110	- Higher grade steel; - optimized strain design for settlement. - Above ground alternative - optimize pipe insulation. - Alternative materials.
Pipeline Installation	350-450	250-350	- Extended winter construction using spray ice. Reduced depth and width of ditching, Improved ditching productivity - detection and avoidance of adverse terrain. Direction drilling of river crossings or high-tech bridges. - Above-ground design.
Pump Stations (including additional pumping for Norman Wells south)	100-140	80-120	- Investigate flow improvers. - Hydraulic/thermal optimization. Assess impacts on Norman Wells south line of increased volume and possibly higher temperatures.
Totals	650 (Avg.)	500 (Avg.)	

Table 11

Research Thrusts for Small Onshore Beaufort Oil

Scenario:	Beaufort Onshore: Includes Exploration and Production of Nominal 100 MB Pool Includes Small Pipeline Extension from Norman Wells		
Prize:	• Lower Exploration Costs and Lower Economic Thresholds • Encourages Exploration		
Element	Base Case cost ($M)	Target Cost Technology Uplift ($M)	Comments and Ideas for Innovation & Research Thrusts
Exploration Drilling	5-1 O/Well (Onshore) 10-20 (Shallow Offshore)	3/Well (Onshore) 6-10/Well (Shallor Offshore)	- Slim hole drilling systems. - Use of ice pads instead of gravel /piles. - Barge mounted drilling systems for year-round use in the Delta. - Hover barges. - Extended use (2 wells??) of spray ice pads in shallow offshore.
Facilities and Gathering Lines	200	150	- Adopt learnings from Alaska, Re: facilities costs. - Use directional wells to minimize production pads (How do they behave in permafrost?).
Production Wells	285	215	- Adopt learnings from Alaska. - Optimize casing downdrag stress.
Total	485	365	25% reduction
Pipeline Tariff (25,000 B/D)	$18/Bbl (initial) $9/Bbl (final)	25% Reduction	See Table 11 for ideas to reduce capital costs of pipeline from Norman Wells to Beaufort.

Table 12

but it needs to be drawn together in the context of this specific scenario).

As already discussed, however, the onshore scenario requires additional reserves to avoid high pipeline tariffs, and therefore, to be economic. Consequently, continued exploration for onshore and shallow offshore resources is needed. Therefore, the exploration drilling has been included in the table as an element for cost reduction. If exploration costs can be lowered, then, operators will be more likely to continue to explore (conversely, more wells can be drilled for a given exploration budget). Ideas for lowering drilling costs are shown in the table.

As discussed earlier, tanker transportation of Beaufort oil appears to be economically attractive for some scenarios. However, tariffs are difficult to confirm without further detailed study. This should be the first step in assessing the tanker option. Tariff is quite sensitive to transit times and as suggested in Table 13, a technical study is needed to determine realistic transit times for various routes out of the Beaufort. Also, tankers require significant storage, and it is not clear how such storage can easily be provided especially in the small development scenarios, where a minimum platform system had been planned. The bigger barrier to the use of tankers would undoubtedly be public perception and concern over environmental disaster. Several items in Table 13 address this fundamental issue.

Research opportunities for the full-scale offshore case (i.e. at 80,000 Bbls/day) are itemized separately in Table 14. Research thrusts are similar to the small-scale offshore case. Also, both the tankers and pipeline cases apply to this scenario. If technology initiatives are taken with respect to lower-cost platforms and pipelines, these will also be applicable to the full-scale offshore case (which may become an attractive option if more reserves are discovered).

Gas Development Scenarios

In this region, natural gas discoveries total about 12 Tcf and 4.5 Tcf of this lies offshore. The largest onshore gas field is Taglu in the Delta with 3 Tcf, which is followed by Parsons Lake with 1.9 Tcf and Niglintgak with 1 Tcf. The most recent study of gas development was conducted by the producers in the period 1987-1991, who applied for an export licence for the gas. This was approved by NEB in 1989, but, since then, the initiative has

Research Thrusts **for Tanker Transportation of Beaufort Oil**

Scenario:	Tanker Transportation of Beaufort Oil		
Prize:	• Less Costly Tariff Hence improved Economics • Tanker Flexibility May Remove Need to Find Additional Reserves		
Element	**Base Case Cost ($M)**	**Target Cost Technology Uplift ($M)**	**Comments and Ideas for Innovation & Research Thrusts**
Tanker Tariff (To U.S. West Coast or Vancouver)	$6- 12/Bbl	$5- 8/Bbl	- Tanker transit and risk analysis with input of experience from Beaufort oil operations, M.V. Arctic, Baltic and N. Russia. Innovative ideas for storage. Optimization of tanker size and numbers for various production scenarios. Field demonstration and data gathering using ice-capable vessel (January - April period).
Risk Reduction and Operational Efficiency			Knowledge of ridge fields and pressured ice along routes and influence on transit times. - Assessment of effectiveness of environmental protection systems - including double hull - oil spill response in ice. Ice impact loads especially glacial ice. Integration and assessment of work to date on structure design, materials, corrosion and ice loads on machinery. Development of fuel-efficient designs. Design of offloading systems in ice. - Ice management around loading terminal/structure.

Table 13

Research Thrusts for Offshore Beaufort Oil Development

Scenario:	Beaufort Offshore: 350 MB Oilfield, Pipeline at 80,000 B/D
Prize:	• Trigger Oil Development at 80,000 B/D • Regional Development • Exportable Technology Development

Element	Base Case Cost ($M)	Target Cost Technology Uplift ($M)	Comments and Ideas for Innovation & Research Thrusts
Offshore Platform (Structure Only)	400	300	- Develop more reliable & less conservative sea ice loads. - Develop ice load protection & mitigative techniques for extreme envents - Develop methods to mitigate adverse dynamic ice loads - Develop optimized structure shape for ice and waves
Topsides including Production Equipment	540	500	- Adopt newest low-cost techniques from other areas - Construction optimization studies.
Development Drilling & Completions	630	550	- Improved method of mitigating / designing for casing down-drag due to permafrost thaw. - Use of deviated / horizontal wells to reduce number of wells Design of deviated wells through permafrost
Offshore Pipeline	270	200	- Faster construction techniques Use spray ice causeways to build off the ice - Assess burial depth vs risk (minimize trenching). - Optimize trenching using ploughs / dredges
Miscellaneous	360	360	
TOTALS	2200	1910	
Pipeline Tariff (16" Line)	$8.60/B initial $3,50/B final	25% reduction	- See table 11 for ideas on capital cost reduction of pipelines

Table 14

stalled due to poor economics based on the latest outlook for gas prices.

The base-case development plan was to transport the gas via a 36 inch pipeline up the Mackenzie Valley to Caroline, Alberta. Initially, only the onshore reserves were to be produced for an initial capital investment of about $2 billion for facilities and over $5 billion for the pipeline. The gas was to be produced at 1.2 billion cu. ft./day. It was to be chilled through the permafrost zones to avoid subsidence. Ultimately, a 36" pipeline required that the offshore reserves would be produced (even though their economics were less favorable).

Some synergism was recognized between oil and gas development. For example, the natural gas liquids could provide additional volumes to an oil pipeline, and oil development at Amauligak would share the development costs of the gas.

Overall, it was estimated that a price of about $3.50/~~million~~ thousand cu. ft. is required for the described scenario. As gas prices are currently below $2.00/thousand cu. ft. (kcf), the project is stalled.

Furthermore, it is recognized that there are significant competing gas supplies, for example it is estimated that at $3.50/kcf, 400 Tcf of gas potential in the Lower 46 can be accessed.

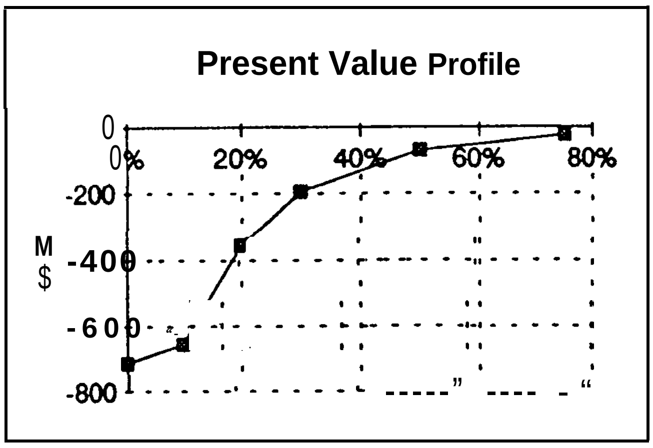
The scenario examined in this study is to produce only the onshore reserves. This tends to give a higher tariff, but avoids bringing in the more costly offshore gas. A 30 inch pipeline is assumed at a cost of $4.5 billion. Facilities are assumed to cost $1.2 billion. The economics are shown in Figure 16 and have been run for the current EMR price outlook which calls for a price of $2.07 /GJ. ($2.22/kcf) by the year 2000. Not surprisingly, the scenario is not economic at that price. In order to be economic (at a 10% return) the gas price would need to be 25% higher than the forecast. Conversely, the pipeline tariff would need to be reduced by 30%. This would require the pipeline to be built for about $3.0 billion compared to the current estimate of $4.5 billion. It is very unlikely that "technology uplift" could lead to such a large cost reduction. In view of the large technology stretch needed, this is not a scenario on which PERD funding should be focused at this time. (Although it should be noted that any research aimed at lowering the costs of oil pipelines through permafrost as well as Arctic facilities will also benefit gas development, which ultimately may be triggered by an increase in the value of gas relative to oil).

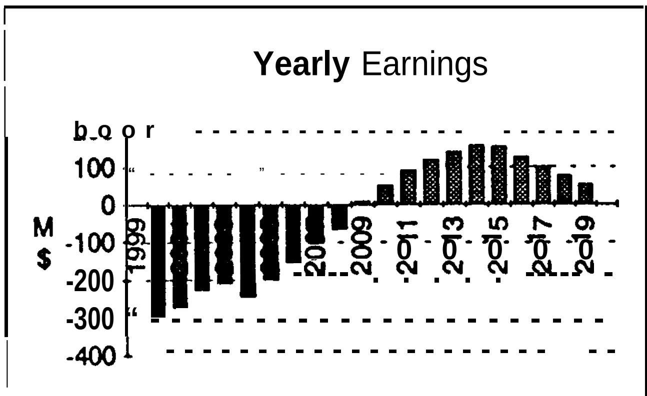
Beaufort Onshore Gas -800 Mcf/Day

Investment	MS
Exploration	0.00
Development Drilling	425.00
Production Facilities	250.00
Gas Gath. & Processing	500.00
Total:	1175.00

Net Present Value	MS
0%	-713
10%	-655
20%	-356
30%	-195
50%	-70
75%	-26

Net Present Value at 10%	($655)
Discounted Cash Flow Return	0%
Project Payout (Years)	.
Cash Flow Productivity Index	-1.62





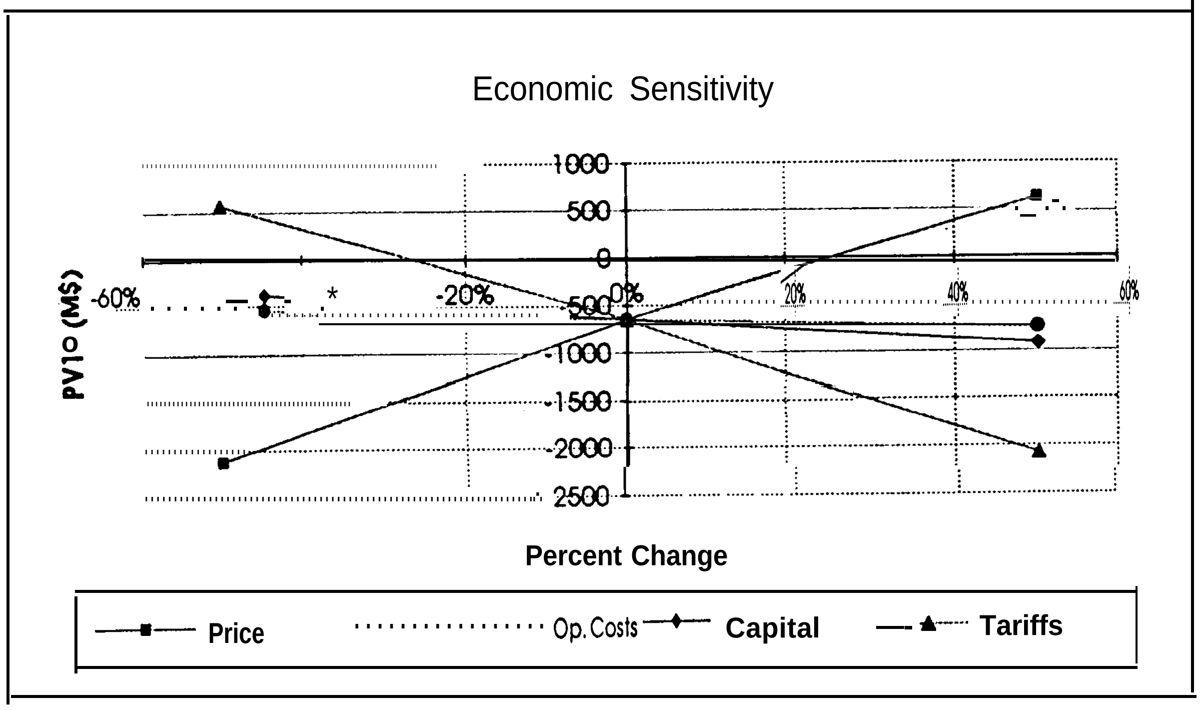


Figure 16

Before leaving Mackenzie **Delta/Beaufort** gas it should be noted that other approaches to remote gas could be considered. These include gas conversion to liquids which is currently being worked on by a number of organizations including Mobil, BP, Shell and Exxon (who is investing $100 million in research). Several quotes indicate that the cost of conversion is around $30 U.S./barrel, but may reach $25 U. S./ Barrel. These prices are not compatible with current price assumptions used in this study. In any case, even if Beaufort gas could be converted at say $20/Barrel it would still have to be produced and the liquids transported to market. However, this is a technology which should be monitored in the years ahead.

The Arctic Islands Region

The Setting and Background

Referring back to Figure 5, the Arctic Islands Region is the most northerly of Canada's oil and gas basins, with most of the activity and the discoveries occurring north of 76 degrees north latitude. The region is obviously very remote and suffers from very harsh environmental conditions. The extended low temperatures lead to permafrost up to 1000 m thick and sea ice which persists for long periods (some channels never clear from year-to-year). A unique feature of the region is the presence of fast-ice over the deep-water channels between the islands. This has allowed industry to conduct relatively low-cost exploratory drilling by using the ice as a floating platform (Masterson et al, 1976). However, development costs in the region will be very high, mainly because of the remoteness and almost permanent ice cover.

Significant discoveries are shown in Figure 17 and listed in Table 15. The region is gas-prone and the largest oil discovery is Cisco at about 300 million barrels (however, the field is located offshore in deep water with an almost permanent ice cover above). The region is prolific in gas with discovered reserves to date estimated at about 17 trillion cu. ft. (and a total potential over 30 trillion cu. ft.). The gas is distributed between onshore and offshore reservoirs.

Oil Development Scenarios

The region is not well-endowed with oil, with total discovered reserves less than 450 million barrels, and as mentioned, the largest discovery is very inaccessible. Even so, the Arctic Islands can claim to be the second Frontier region to produce commercial oil. Commencing in 1985, Panarctic Oils Ltd. has been seasonally producing oil out of the Bent Horn field on Cameron Island. However, it is a very small operation consisting of 2-3 tanker loads (up to about 300,000 barrels total) for the summer season. The field being tapped, Bent Horn, is estimated to contain about 6

ARCTIC **ISLANDS**
SIGNIFICANT DISCOVERIES

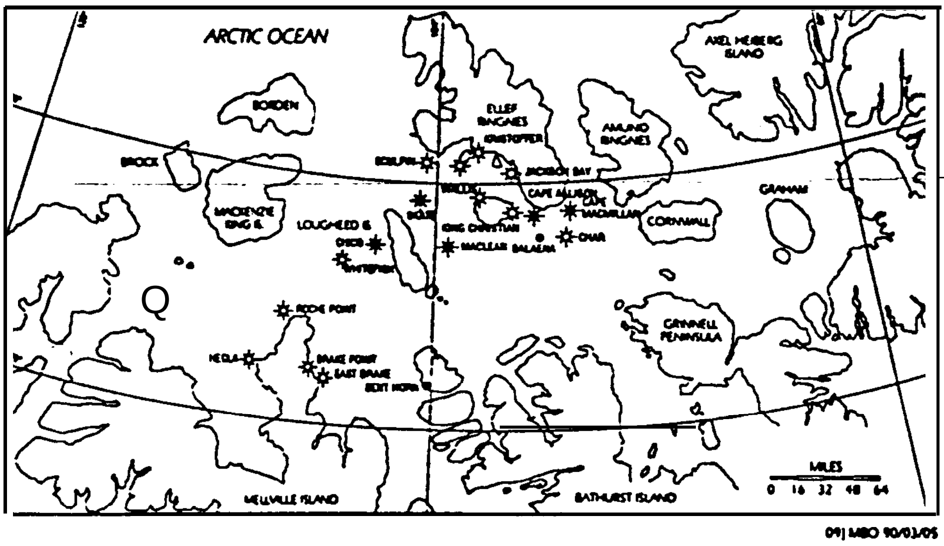


Figure 17 (Dingwall, 1990)

Arctic Islands - Significant Discoveries

Field	Oil (MBbl)	Gas (Tcf)
Cisco	300	0.2
Drake		5.4
Hecla		3.7
Jackson Bay		1.0
King Christian		0.6
Kristoffer		1.1
MacLean	20	0.6
Thor		0.7
Whitefish		2.7
Others	170	1.0
Total	490	17.0
Additional Potential	500-1500	15-20

Table 15 (Dingwall, 1990; GSC, 1983)

million barrels only. There is a much larger oil field at Cisco with an estimated 200 - 300 million barrels, but it is in much more difficult ice and is offshore in about 300m of water. The current view is that development of Cisco will require a considerable uplift in price and that there are much easier Frontier oil fields to produce first. Therefore, this study has not developed an oil scenario for the Arctic Islands. Neither is it considered appropriate to devote PERD funding for research aimed at such a scenario at this time, (although it should be noted that research that may be done for other Frontier scenarios could apply).

Gas Development Scenarios

Gas development scenarios based on both pipelines and LNG tankers have been studied.

The Polar Gas Project was a scheme to construct a natural gas pipeline from the Mackenzie Delta to Alberta to first produce the gas reserves from that region. Later, a pipeline system would be extended to Melville Island and beyond to tap into the Hecla, Drake Point and Whitefish gas fields (total reserves about 11 Tcf). However, as already discussed, the economics for Mackenzie Delta gas are not favorable within the current gas price outlook. The economics of producing the Arctic Islands gas by pipeline would be even worse and therefore have not been worked in this study.

Another project to produce Arctic Islands gas was studied in the late 1970's. In this, the Arctic Pilot Project, the intent was to test the feasibility of an LNG (liquefied natural gas) system to produce and transport LNG to Eastern Canada markets using ice breaking LNG tankers. The cost of the project was estimated at $1.5 billion (1980) not including the southern terminal. The reserves to be produced amounted to 2 Tcf. The project has been shelved, due to poor economics.

industry's current view is that other gas reserves will be produced more cost effectively than those in the Arctic Islands, and the economics stretch is considerable. For these reasons, this scenario has not been examined for the current study.

The Grand Banks Region

The Setting and Background

The Grand Banks region is located off the coast of Newfoundland at about the 48 degree N latitude. The general water depth over much of the Banks is 150 m or less. Despite its southerly latitude relative to say, the Beaufort Sea, the region is subject to ice. Pack ice is often driven south by the cold Labrador current. This pack ice can be up to 1 m thick, but is usually broken up into quite small floes due to the action of the North Atlantic swell. Pack ice doesn't occur every year on the Grand Banks, but its presence has to be taken into account for long term design and operations criteria A more formidable ice feature is the iceberg. These calve off the glaciers of Greenland and are eventually carried south by the Labrador current to reach the Grand Banks region. In some years, as many as 2000 icebergs cross the 48 degree N latitude and they can be several million tonnes in mass. Permanent platforms have to be designed to resist the forces of collision with such icebergs. Also, floating production vessels and shuttle tankers have to avoid collisions with the larger icebergs and need to be designed to withstand collisions with the smaller undetectable glacial ice pieces.

Icebergs can also scour the sea floor, although the frequency of scour on the Grand Banks is quite low.

In addition to the ice hazards, the North Atlantic can produce fierce storms, with wave heights similar to the North Sea. Icing due to sea spray can also be a problem.

Despite these severe environmental characteristics, the industry has successfully adapted floating systems, in use in other parts of the world, to conduct exploration. Additional operational safety techniques involving iceberg detection and towing have worked well, and to date over 115 exploratory wells have been drilled off Newfoundland with 20 significant discoveries. Oil discoveries have been concentrated on the Grand Banks in the Jeanne d'Arc Basin, see Figure1 8.

GRAND BANKS
SIGNIFICANT DISCOVERIES

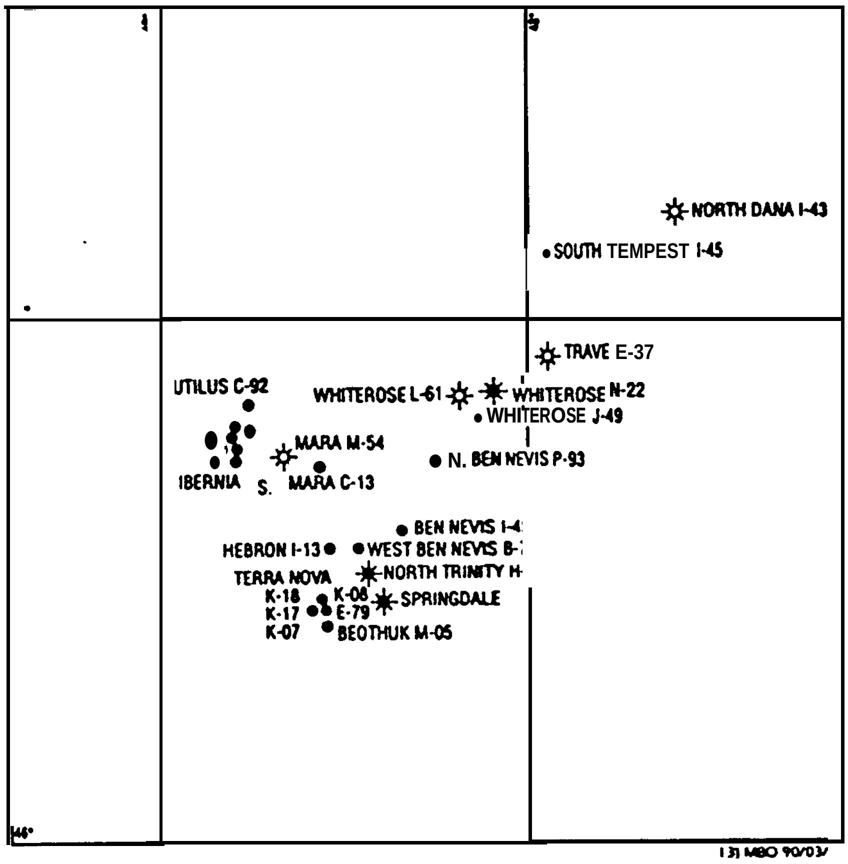


Figure 18 (Dingwall, 1990)

A listing of significant discoveries on the Grand Banks is given in Table 16. Most of the interest has been in the 1.6 billion barrels of oil discovered, although 4 trillion cu. ft. of gas has also been found.

Four discoveries, Hibernia, Terra Nova, Whiterose and Hebron contain most of the oil, and are likely prospects for development. Fields of these sizes would certainly be economic in the North Sea, but off Newfoundland the costs are higher, mainly because of the need to cope with ice and icebergs, but, also because of a less-developed infrastructure.

Methods of coping with ice and icebergs have been developed and further effort to improve these methods will undoubtedly lead to improved economics and investor confidence. As well, with the commencement of Hibernia, the infrastructure costs will be improved for future projects.

Grand Banks Significant Discoveries
(CNOPB, 1992)

Field Name (Operator)	Oil MBI	Gas Bet	Liquids MBI
Hibernia (HMDC)	666	1,017	111
Terra Nova (Petro-Canada & Husky	406	269	14
Hebron (Mobil)	195		
Whiterose (Husky)	178	1,509	56
West Ben Nevis (Petro-Canada)	25		
Mara (Mobil)	23		
Ben Nevis (Petro-Canada & Husky)	19	229	30
North Ben Nevis (Husky)	18	115	4
Springdale (Esso)	14	236	
Nautilus (Mobil)	13		
South Tempest (Mobil)	8		
Fortune (Husky & Esso)	6		
South Mara (Mobil)	4	144	8
North Dana (Mobil)		470	11
Trave (Husky)		30	1
Totals (March 31/92)	1,576	4,019	237

Table 16

Oil Development Scenarios

As already discussed, Hibernia is under development using a fixed platform with built-in storage and using shuttle tankers to transport oil to market. The total initial capital investment in Hibernia is $5.2 billion and the breakdown of costs is given in Table 17. The recoverable reserves at Hibernia are about 650 million barrels and the development is planned to yield 110,000 barrels of oil per day, commencing in about 1997. The Hibemia platform is the first in the world to be designed to withstand collisions with large icebergs (6 million tonnes), (although the probability for collisions with icebergs of any size is low, i.e. a return period of about 12 years). The platform shape is configured to provide protection against icebergs, but, because of its bulky form (caused partly by the need for oil storage), the wave loads are also quite high. If it was not for the iceberg problem, however, the structure shape would be much more like a North Sea gravity platform and the costs correspondingly lower.

Hibernia Development Project Costs
(CNOPB, 1992)

Activity	$M (Cdn)
Pre-Project	41
OPCP	334
Bull Arm Site	426
GBS	1179
Topsides EP/PSC	543
Modules	1096
Insurance	110
Assembly & Hookup	440
OLS / Pipelines	100
Tankers	436
Development Drilling	150
Contingency	283
TOTAL	$5139

Table 17

Another development under consideration is Terra Nova. Terra Nova has between 350-400 million barrels of recoverable oil and is in about 95 m of water. The development is based on a monohull ship-shape vessel with subsea wells. The vessel would be turret-moored, and have a double hulled, double-bottomed configuration with storage **for 600,000 barrels.** Overall length would be 250 m and width 42 m. Thirty-four wells would produce the field, each in a cased glory hole to protect against iceberg scour of the sea floor, Peak average production rate would be about 100,000 barrels per day. (Bruce, 1991)

Three shuttle tankers would offload the oil, the tankers would be double-hulled and ice-strengthened. As production declines, the tankers would reduce from 3 to 1. Average annual downtime is assumed to be about 70 days. This could occur if large icebergs are on a collision course, cannot be diverted, and the production vessel has to be moved . The production vessel and tankers will need to be designed to resist impact with bergy-bits. Total capital cost of the Terra Nova project is about 60°A of the Hibernia capital cost. The percentage breakdown of capital costs is given approximately below. (Clark, 1992)

Cost Breakdown - Terra Nova

Production Component	**% cost**
Production Vessel	7
Turret	3
Topsides	11
Subsea Equipment Including Flow tines	17
Tankers (3)	13
Development Wells	23
Management, Engineering, Overhead, Insurance, Taxes, etc., Predevelopment, etc.,	26
Total	100%

Table 18

Generic Oil Development Scenarios

Two generic scenarios will be examined based on floating and fixed platforms; floating cases of 200 million barrels and 350 million barrels of recoverable oil will be considered. A fixed platform case is also considered.

The economics generated in this study are not meant to be definitive, nor are they likely to coincide exactly with those developed by others, including the operators and governments. However, they are consistent across scenarios and for the different Frontier regions. The main purpose of the economic comparisons is to examine sensitivities to technology improvements. The general input assumptions are as described earlier in this report.

Floating Production; 350 Million Barrel Oilfield

The total capital cost for this case is based on the paper by Rodgers (1990) The cost breakdown is based on the percent distribution given for Terra Nova, and supplied from a personal communication with PetroCanada (Clark, 1992). General input assumptions and the economic summary are given in Figure 19.

This scenario has positive economics with a rate return of about 13% and a net present value at 10% of $290 million. The scenario appears to be quite robust as shown in the sensitivity analysis results, Figure 19. Even if the oil price drops to $18, the return is still 10%. Conversely, the capital costs could escalate by 17% and the project is still economic.

In this scenario, the role of improved technology or knowledge could, perhaps, be most importantly applied in reducing uncertainties, and demonstrating to potential investors that risks associated with the unique physical environment can be managed. The key research thrusts discussed later recognize this rationale as well as striving for lower capital costs.

Floating Production: 200 Million Barrel Oilfield

Costs for this case have been proportioned from the previous scenario. A peak average daily production is 48,000 barrels/day.

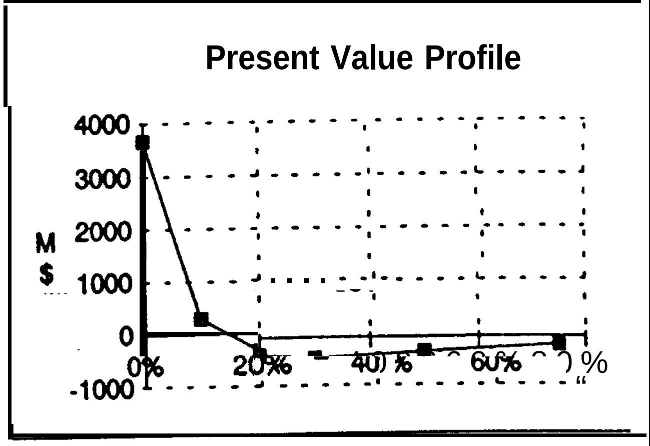
Other input assumptions and the economic summary are given in Figure 20. The scenario is economic with a return of 8%. The present value at 10% is -$127 million and this increases to +$100 million with a 20% reduction in capital cost.

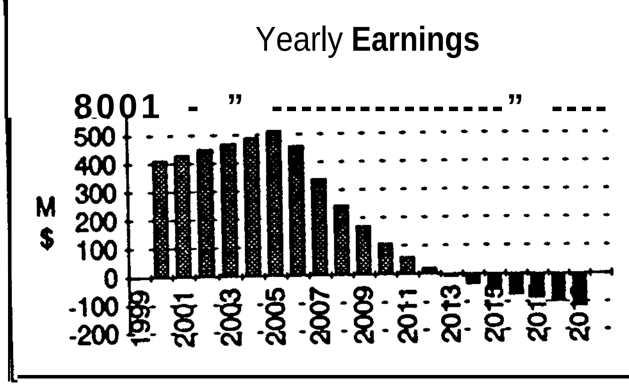
East Coast -350 MBbl Floating

Investment	MS
Exploration	40.00
Development Drilling	1150.00
Production Facilities	2500.00
Gas Gath. & Processing	0.00
Total:	3690.00

Net Present Valua	M$
0%	3661
10%	289
20%	-325
30%	-392
50%	-281
75%	-161

Net Present Value at 10%	$289
Discounted Cash Flow Return	13%
Project Payout ('Yearn)	12
Cash Flow Productivity Index	0,11





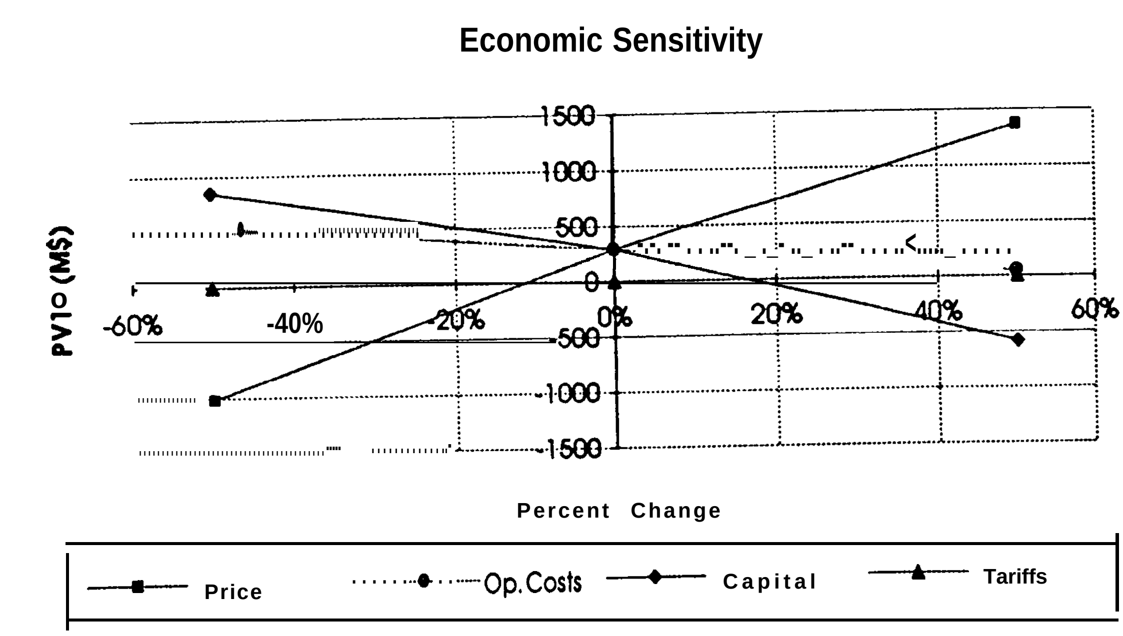
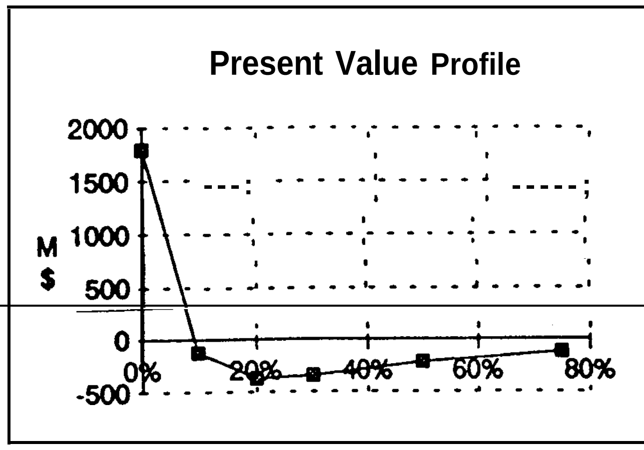


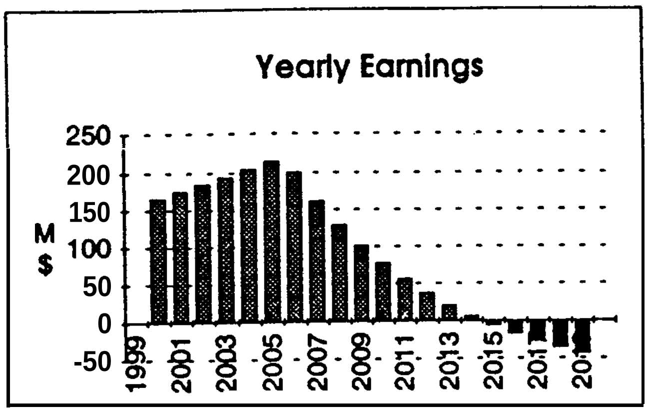
Figure 19

East Coast -200 MBbl - floating

Investment	M$
Exploration	40.00
Development Drilling	675.00
Production Facilities	1780.00
Gas Gath. & Processing	0.00
Total:	2495.00



Net Present Value	M$
096	1792
10%	-127
20%	-372
30%	-345
50%	-219
75%	



Net Present Value at 10%‹ 2 °	($127)
Discounted Cash Flow Return	8%
Project Payout ('Years)	15
Cash Flow Productivity Index	-0.07

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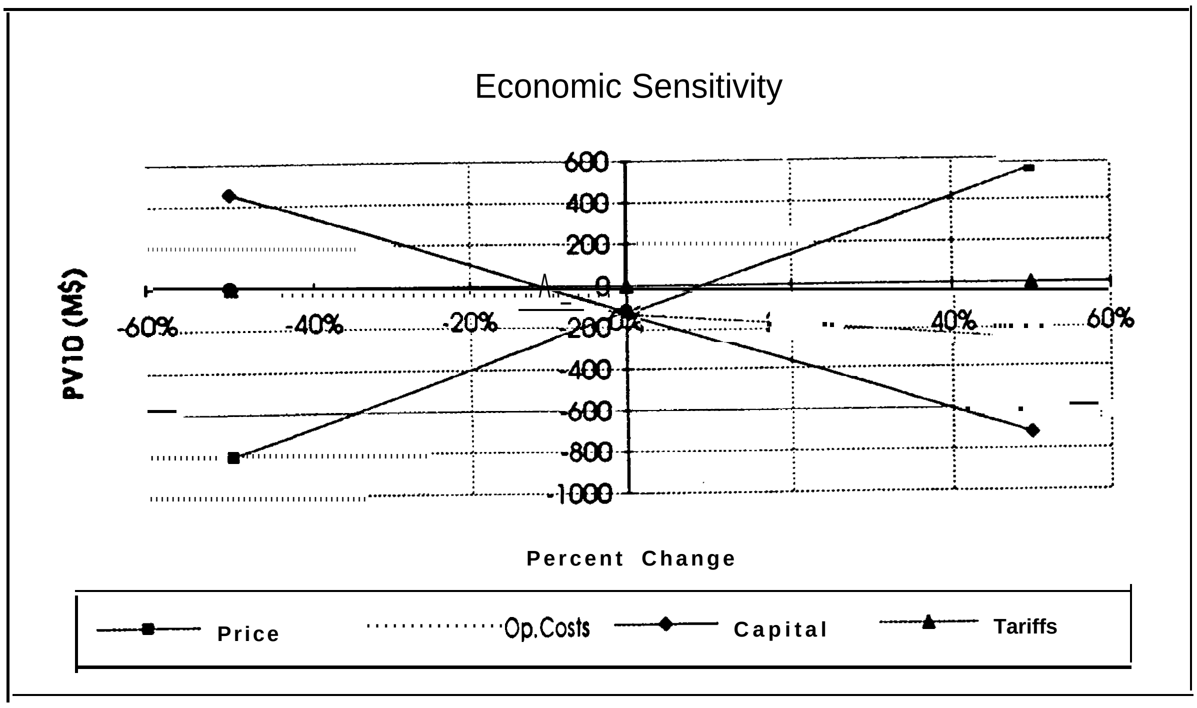


Figure 20

Fixed Platform: 500 Million Barrel Oilfield

Costs for this case have been obtained from published data for Hibernia, suitably factored. The elements of the scenario are a fixed iceberg-resistant platform with shuttle tankers for transportation, gas is reinfected.

The input assumptions and economic summary are given in Figure 21. This scenario has a return of 12% and a present value at 10% of $270 million.

However, based on the previous analysis, this pool size would have more attractive economics if a floating system is used.

Technology Improvements and Research Opportunities

The 350 million barrel floating production scenario will be considered first. The basic elements and issues for this scenario are itemized in Table 19. As previously indicated, this scenario is already economic using base-case costs. The priority in any technology initiatives should be to:

- Minimize downside risks
- Reduce the perception of risk associated with floating production
- Confirm, test and improve the proposed technology

Ideas and research thrusts to minimize downside risks are also itemized in Table 19.

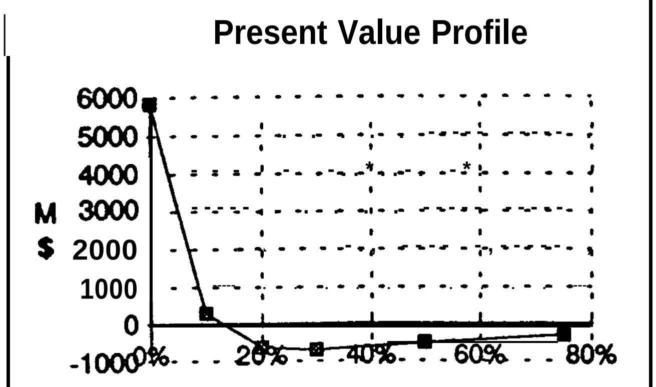
It would also be very helpful to PERD planning if, for this scenario, a comprehensive operational simulator and risk model is developed. This would help provide a focus on priorities to improve operational efficiency and confirm such things as ice avoidance assumptions. The outcome of such a study would be a much more precise understanding of the performance levels needed for ice detection, ice management and ice tolerance. This tool could be used for various East Coast locations having a range of ice conditions statistics.

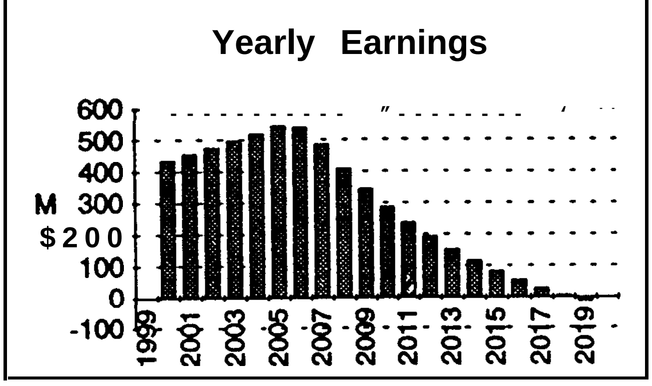
East Coast -500 MBbl - Fixed Platform

Investment	MS
Exploration	0.00
Development Drilling	1750.00
Production Facilities	2900.00
Gas Gath. & Processing	0.00
Total:	4650.00

Net Present Value	MS
0%	5825
10%	270
20%	-637
30%	-711
50%	-518
75%	-317

Net Present Value at 1096	$270
Discounted Cash Flow Return	12%
Project Payout (Years)	13
Cash Flow Productivity Index	0.08





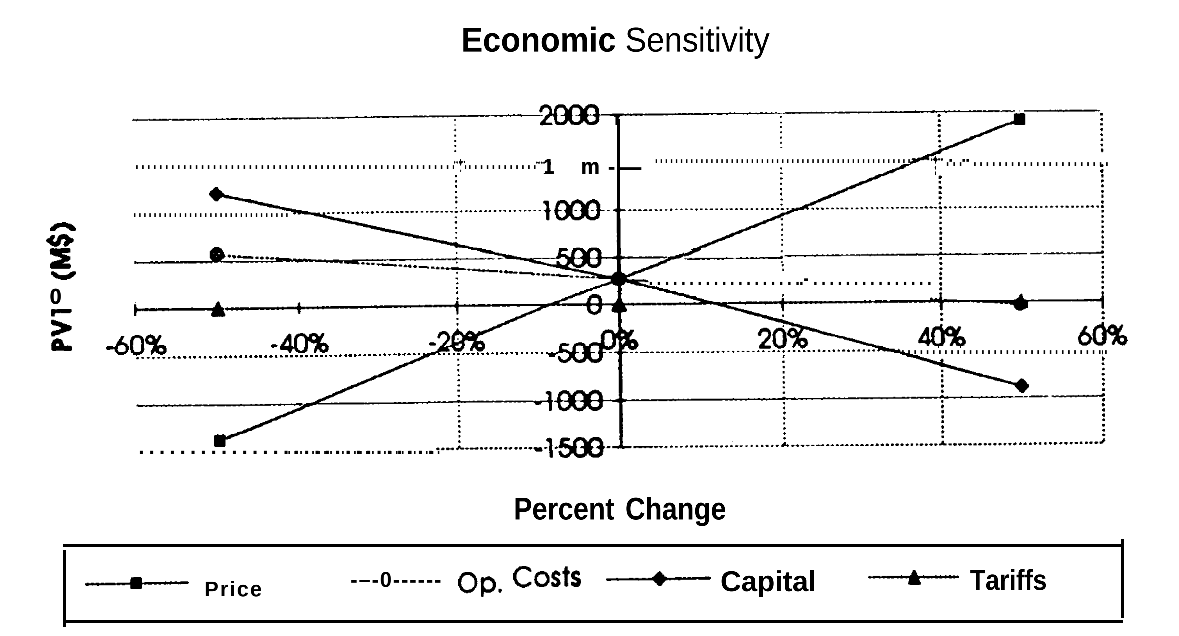


Figure 21

Research Thrusts for Grand Banks Floating Production

Scenario: Grand Banks Floating Production: 350 Million Barrel Pooi

Prize:
- improved Economics
- Minimize Downside Risks
- Reduce Perceptions of Risk

Element or Issue	Base Case Cost M$	Target Cost Technology Uplift ($M)	Comments and Ideas for Innovation & Research Thrusts
Vessel, Turret and Topsides	770	600	- This scenario already has good economics, the priority is to minimize downside risks and reduce the perception of risk. - Testing Critical elements of turret mooring system, including fluid transfer system.
Tankers	480	400	- Configuration / determination of ice strengthening required by production vessel and tankers. - Design features to provide limited ice tolerance should be investigated and tested, if such tolerance is needed to enhance operational efficiency and economics.
Subsea Wellheads and Flowlines	630	500	- Optimization of wellhead protection against iceberg scours.
development Wells	1150	900	- Significant costs are allocated to development wells, innovative thrusts to reduce these costs should be a goal.
Operational Efficiency	80%	90%	- A comprehensive operational simulator / risk model should be developed for East Coast floating systems in order to provide a focus on areas of improvement for operational efficiency and confirm ice avoidance assumptions. An outcome of such a study / model would be a precise understanding of the performance levels needed for ice detection, ice management and ice tolerance.
Risk and Perceptions of Risk			- To reduce perception of risk, as well es to provide design data, experimental simulation of the impact of glacial ice on the production vessel and tankers should be implemented.

Table 19

Other ideas to **reduce the perception** of risk and to provide more precise design data are listed. In the longer term, design approaches to give significant ice tolerance should be developed, as discussed by Masterson and Wright in their recent review of ice research for PERD Task 6 (Masterson and Wright, 1992). The issues and research thrusts for smaller fields are similar to those already discussed.

The elements of a generic 500 million barrel pool, to be developed with a fixed platform, are shown in Table 20, together with ideas for improvements and research thrusts. Optimization of the platform structure recognizing the often conflicting needs of ice resistance, wave resistance and storage is a worthy goal. It is one which can benefit from the most recent insights into ice mechanics and ice loads, as well as from possible future experiments to simulate iceberg impacts on offshore structures. (Masterson and Wright, 1992)

It is not clear if the cost of the "topside" decks and processing facilities can be lowered further. Possibly, the Hibernia and recent North Sea experience could be incorporated to achieve lower costs?

Again, the issue of optimizing an integrated ice detection and predictive system to minimize downtime during tanker loading is key to improving efficiencies. The degree of ice strengthening required for the shuttle tankers requires careful scrutiny, and further work on impacts with small icebergs and bergy-bits is recommended to provide the basis for design/operational optimization.

Development wells are a high-cost item and a research thrust to lower these costs would be desirable. Recent developments from other areas such as the use of horizontal wells should be examined.

In addition to the two key oil development scenarios of fixed and floating platforms, it is worth noting that there are several small oil discoveries, i.e. 50 million barrels or less, which have been discovered, and undoubtedly, more will be found. As noted by Chipman (1992), in the North Sea, there is a trend to develop these smaller fields using minimum systems, and to tying them in using subsea systems to existing production platforms or floaters. The maximum distance which can be reached depends on the reservoir and fluid characteristics, but, 10 km is currently typical (although much longer distances are achievable if the fluid is mostly gas). To fully exploit this approach, subsea multi-phase pumping (and metering) will probably be needed. This is a research area of significant importance to the future development of Newfoundland's smaller oilfields and would be a suitable topic area for PERD support.

Research Thrusts for Grand Banks Fixed Platform Production

Scenario: Grand Banks Fixed Platforms: 500 Million Barrel Pool

Prize: Improved Economics: Lower pool size for threshold development

Element	Base Case cost ($M)	Target Cost Technology Uplift ($M)	Comments and Ideas for Innovation & Research Thrusts
Platform Structure	1000	700	- Optimize platform shape to minimize costs, recognizing iceberg impact and waves as controlling phenomena, as well as need for storage. Incorporate new learnings and ongoing research on 100al ice pressures and limit-states design. Large iceberg impact simulation tests to provide input to above.
Topsides	1000	1000??	- Incorporate learnings from Hibernia project.
Tankers and Offloading	400	350	- Refine and develop confidence in ice detection techniques, develop integrated approach (satellites, ground wave and microwave radars). Optimize tanker operations and design for impacts with small pieces of glacial ice. reduce downtime by improving ice tolerance.
Development Wells	1750	1500	- Reduce number of wells by using deviated and horizontal well techniques. Lower cost methods of remote wellhead protection if subsea wells part of development.
(Mist)	500	500	
Total	4650	4050	

Table 20

Offshore Labrador Gas

Drilling off Labrador took place during the 1970's and early 1980's. Several significant gas fields have been discovered, see Figure 22, for a total **discovered resource of about 5** trillion cu. ft. The region is considered to have a **potential of** about 12 -20 trillion cu. ft. Several of the larger discoveries are in manageable water depths (i.e. 150 m), and relatively close to shore (i.e. 70 km). **However, the ocean sea floor and ice conditions are formidable. Icebergs are the main problem. These are much more frequent than on the Grand** Banks and they mostly move through the area during the summer months. The icebergs inhibit floating operations, and would require massive platforms to withstand their impacts. Worse still, the icebergs are large enough to scour the sea floor and present a hazard to **subsea wellheads, manifolds and** pipelines. In addition to icebergs, the **region is covered by pack ice from January to June and** in the summer, severe storm-driven waves **can occur.**

Several studies have been conducted to investigate development concepts with related costs and economics. The most recent by Sheppard et al (1992) considered a complete subsea system, with a multi-phase pipeline to shore, with a subsequent pipeline to Eastern markets (e.g. Montreal).

The study estimated the supply price for the gas to be about $3.30/kcf (at a 10% project return). It also concluded that the gas wasn't competitive and would not be for some time given the gas price outlook. The study also recognized two key technology areas requiring further work.

- Improved methods of protection of subsea facilities and pipelines against iceberg scour, and specifically mentioned improved methods of trenching.
- Mult-phase flow over long distances including the issue of metering and hydrate formation.

The above technical issues are also relevant to other Frontier regions (as has been discussed).

Because of the recent study referenced above, which included a review of technology, costs and economics, this study has not addressed the Labrador gas scenario in any **further detail.**

LABRADOR

SIGNIFICANT DISCOVERIES

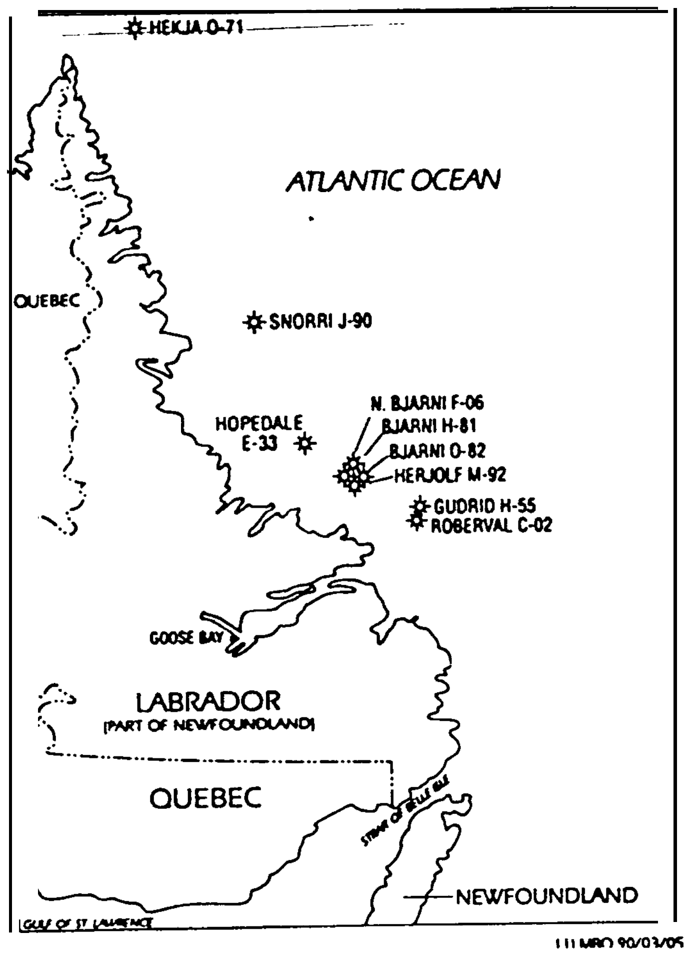


Figure 22 (Dingwall, 1990)

Offshore Nova Scotia

The Setting and Background

This region lies close to Sable island at about latitude 44 degrees N. As shown in **Figure 23, most** of the discoveries have **been gas. Recoverable reserves are estimated to be about 50 million barrels of oil, 90 million barrels of condensate, and 5 trillion cu. ft. of gas. Ultimate potential could** be between 250 and 800 MBbl of oil and about 15 **trillion cu. ft. of gas.** (Dingwall, 1990) (GSC, 1989)

This offshore region is one of the few in Canada that is ice free. Therefore, conventional offshore technology, as being used in other parts of the world can be used **here without any changes.** However, the gas reservoirs tend to be ovepressured and at high temperature, this requires care in drilling and completions.

NOVA SCOTIAN SHELF
SIGNIFICANT DISCOVERIES

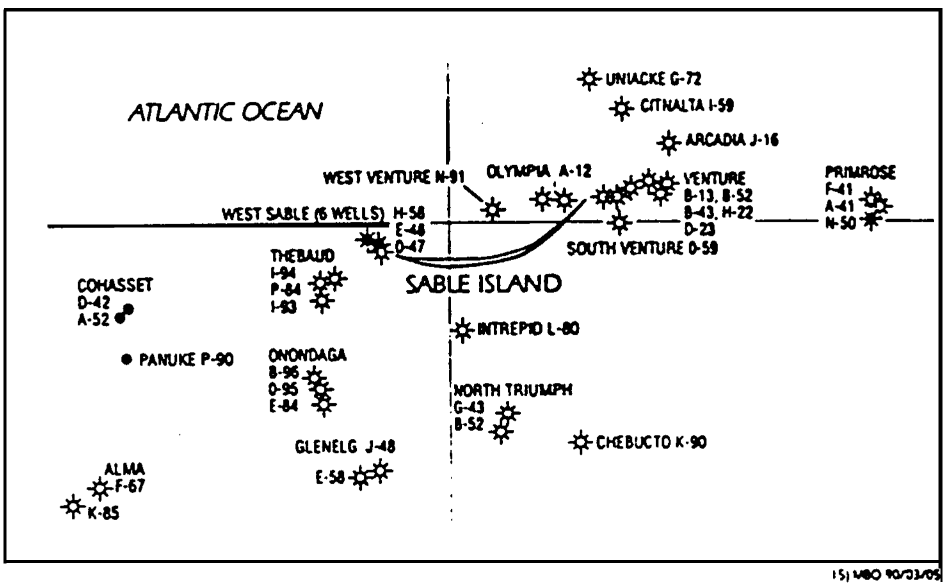


Figure 23 **(Dingwall,** 1990)

oil

No large oil discoveries exist nor are they expected. However, because of the relatively straightforward offshore environment and shallow water, quite small oil fields can be economic. An example is the Cohasset development now underway. This is the first offshore development in Canada and taps into two oilfields with a total of about 40 to 50 million barrels of oil in 40 m of water. It is a conventional low cost production scheme with a production jack-up, production jacket, a Calm buoy, a storage tanker and a shuttle tanker. Production rates will be up to 40,000 Barrels per day, but production will shut down during the stormy winter months.

In view of the positive economics of the above development, and the limited oil reserves expected in this region, it was decided not to run a Nova Scotia offshore oil scenario in this study. Also, the technology needs are being met by adoption of conventional offshore systems, and its not likely that a PERD effort can add significant value, It should be noted, however, that some of the initiatives discussed for Nova Scotia gas are also of benefit to future oil development.

Gas

A recent study was conducted by the Nova Scotia Department of . Natural Resources on gas development options (Indeva, 1992). Total recoverable reserves in the seven gas fields total about 4.2 trillion cu. ft. Cases were studied at two production rates, 300 and 400 million cu. ft./day. In all but one case, gas was to come ashore at Sheet Harbour N. S., in the one case a pipeline to Boston was assumed.

Conventional North Sea technology was assumed in the study with special recognition of the high pressure, high temperature reservoirs.

The gas prices required for various rates of return are shown in Table 21. Case 3 is the one with a pipeline from the offshore field to Boston. Case 1 D incorporates an LNG plant at Sheet Harbour. As can be seen, the more favorable cases give a required gas price for a 10% return, in the range of $2.16-$2.30 per thousand cu. ft. These prices appear to be close to the EMR forecast for 1998. Hence the development is close to being economic.

Nova Scotia Gas Fields
Required Gas Prices to Achieve Rate of Return

Case	20% DCFR ($Can/kcf)	1096 DCFR ($Can/kcf)	S96 DCFR ($Can/kcf)
Case 1A	3.33	2.16	1,70
Case 1 B	3,62	2.30	1.77
Case 1 D	>4.30	3.46	2.70
Case 2A	3.35	2.16	1.70
Csse 2B	3.25	2.18	1.74
Case 2C	4,26	2.57	1.92
Case 3	>4.30	3.82	2.89
Case 4	2.90	1.89	1.51

Table 21

It is also expected that the implementation of technology improvements could improve these economics, these have been identified as:

1. Use of horizontal wells to reduce the well count
2. Optimization of multi-phase flow between **fields**
3. **Optimized hydrate control in flow lines**
4. **Use of subsea systems rather than satellite platforms, This** would require the use of **multiphase flowmeters.**
5. Use of unmanned satellite Platforms with remote control (with associated cost savings because of smaller size).

In the context of environmental loading, the colder air temperatures **in this region than** in the North **Sea** will require careful consideration to load build-up due to spray ice (as well as methods of mitigation).

As will be discussed later, because this scenario is close to being economic, it **would be appropriate for PERD research** to focus on opportunities (such as those listed above) which could **further enhance** this **scanario.**

Discussion of Scenarios and Technology Opportunities

The intent of this study is to focus on Frontier scenarios for oil and gas which have a good chance of being implemented if 'technology uplift' can enhance the economics and minimize risks and uncertainties. The intent being to identify technology thrusts for PERD which, if successful, could trigger economic Frontier development and wealth creation. The work discussed so far in this report has reviewed each scenario and, in most cases, calculated cost reductions necessary to achieve threshold economics. Some scenarios also require additional reserves to be discovered.

The main oil scenarios analyzed are shown in Figure 1, in which the oil price necessary to achieve a 10% return is shown for each scenario. Also shown in Table 1 is the oil price needed, after what is considered to be a plausible cost reduction achieved through technology uplift. Scenarios requiring additional discoveries are also identified.

On the premise of a 'bird-in-the-hand being worth two-in-the-bush," it would seem appropriate to first set the key technology thrusts for those scenarios which do not require additional reserves to be found in order to be economic.

Mackenzie Delta/Beaufort

For the Beaufort, this leaves just two scenarios:

- A 350 MB offshore oil field produced via shuttle tankers. There are many variants of this scenario, ranging from seasonal production using existing vessels to year-round transportation using Arctic class tankers.
- A 35o MB offshore oilfield produced at 35,000 B/D via a 12" dia. extension from Norman Wells.

Both of the above scenarios appear to be potentially economic at $20/Barrel especially if technology thrusts can further lower costs.

It should also be noted that these two scenarios are not mutually exclusive. For example, a seasonal tanker operation could precede either a pipeline or year-round tankers.

The recommended technology thrusts to achieve lower costs for these scenarios are described in Tables 10, 11 and 13. These will not be repeated here in detail, but summarized as main topic areas, they are:

- Offshore structures in ice
- Arctic tankers and terminal operations
- Offshore pipelines in ice-scoured areas
- Development drilling and completions
- Pipelines through permafrost regions

These should be the primary targeted engineering topic areas for PERD with respect to the Beaufort. The goal would be to focus the R & Don these topic areas to achieve lower costs and very reliable and predictable systems.

It is of interest to note that if progress is made in the above goals, then other scenarios also benefit. These include the development of yet-to-be discovered oilfields, both onshore and offshore.

An additional spur to find such fields would result from R & D aimed at lower-cost exploration, both onshore and offshore. Research thrusts to achieve lower-cost exploration are described in Table 12, and would also be worthy candidates for PERD support, but in themselves would not trigger development.

With respect to Mackenzie Delta Gas, it is unlikely that technology improvements could create a competitive gas supply. Therefore, it shouldn't be a focus of PERD R & D at this time. However, any research relating to an Arctic oil pipeline could have spin-off benefits for an Arctic gas pipeline. So the gas scenario could finish-up significantly improved, even though it may not be a primary focus for PERD R & D.

Grand Banks

If we initially exclude scenarios which require further discoveries, then the East Coast boils down to one generic scenario of floating production. In Figure 1, it will be seen that the scenarios based on a 350 MB and 200 MB pools are both economic, but, they can be further improved with technology uplift, or alternatively their down-side risks can be minimized.

The recommended technology thrusts for the floating production scenario have been itemized in Table 19 in some detail. The main areas are as follows:

- Floating production vessels and tankers for iceberg-infested and stormy regions.
- Operational simulator and risk model to integrate ice detection, ice avoidance and ice design criteria for production vessels and tankers; leading to optimized, minimum risk systems,
- Subsea systems including multi-phase transport and metering, as well as iceberg-scour protection of wellheads and flowlines.
- Development drilling and completions

The above should be the primary targeted engineering topic areas for PERD with respect to improving the economics of Grand Banks oil development. Additional safety-related evacuation and environmental-response topic areas may be warranted.

Again, it is worthy of note that if research is focused on the above main areas, many of the results are applicable to the hypothetical, future 500 MB discovery, fixed-platform scenario. (But, this scenario is, perhaps, of secondary importance because it requires the discovery of a field of a size not considered likely; i.e. future discoveries are expected to be smaller).

Nova Scotia Gas

Of all the Frontier gas scenarios, it appears that **offshore Nova** Scotia gas is the closest to an economic development, but, the prospects could be improved with 'technology uplift". Research topic areas common to other **regions include:**

- Development drilling and completions (including horizontal wells under over-pressured, high temperature conditions)
- Subsea systems and multi-phase flow .

Topic areas of special importance to this **region include:**

- Use of minimum, unmanned satellite platforms
- Structural icing due to sea spray (risk assessment and mitigation)

Collaboration in Research

If PERD adopts the scenario approach with the associated technology thrusts described, then the opportunities for collaboration and alignment with other stakeholders become significant; this is because:

- The research **will have a high probability of matching the research needs of the petroleum companies.** If appropriate mechanisms are devised, then cost-sharing with industry is very possible. Despite the current financial state of the industry, if the research is seen as adding value, then industry will want to collaborate, even if the collaboration, is in the near term, limited to contributions in-kind (say of staff time or data sets, etc.)
- If the research is seen as helping to trigger a development, or enhancing the economics, and minimizing risks, then the regional governments, petroleum boards and communities will likely be very supportive. In some cases, funding and the support for involvement of local organizations could be available.
- Other Federal groups with responsibilities for regional development, e.g. DIAND, will likely be very supportive and be willing to collaborate if the research is seen as triggering activities having significant regional benefits.
- Research Institutes, supported partially by industry and government, e.g. C-CORE, C-FER, are already using the scenario approach for research planning. They will be very keen to align their research thrusts with those of PERD if their supporters see the benefits.
- Technology performers in the governments, e.g. The National Research Council, are committed to focus on the creation of national wealth. This is exactly what a scenario-driven research plan for PERD will do, and will help point the way for our national laboratories.
- University research granting agencies such as the Natural Sciences and Engineering Research Council (NSERC) are

also committed to encouraging research aligned with national needs and priorities. Universities who align their R & D with the PERD technology thrusts will have an excellent chance of accessing NSERC research grants, because the rationale will be very visible and easily referenced.

- Several topic areas identified for research thrusts are of interest to other nations. There is a high probability of achieving international collaboration in most of the topic areas. In some cases, Canada would do the work and other nations would jointly fund, and in other cases, it would be vice-versa.

In order to implement these collaborative opportunities, PERD will need to set some goals and create mechanisms for coordination and leadership. Recommendations in this area will be made later.

Recommendations for PERD Strategy

Based on this study it is **our opinion that there are significant opportunities relating to Canada's Frontier oil and gas, which, if pursued, can** create wealth for the Nation. PERD strategy needs to be aligned with these opportunities. In order to achieve alignment, the first step is for those involved in PERD to have a common vision of the future. Such a vision ought to **be of a PERD organization advancing technology and science in those areas** which can "make a difference" in triggering the development of Canada's Frontier hydrocarbon resources; and, also, in ensuring that the knowledge exists to develop these resources in a safe and environmentally sound manner.

To achieve this vision, an appropriate strategy and **process is required. Strategy development is the responsibility of the new Task 6 Steering committee to whom we suggest that key elements** of the Task 6 strategy should be as follows:

1. Identify Frontier scenarios which can be economic without price growth (the results of this report)

2. Develop a process to create an awareness in all the participants in PERD of these scenarios, as well as the technology goals needed to enhance the economics to an acceptable level.

3. Develop a process to ensure that innovative ideas and research thrusts aimed at the key technology goals are brought forward as proposals (regardless of their origin).

4. Adopt a criteria for selection of proposals which ensures maximum effectiveness in the creation of economically attractive Frontier developments.

5. Create the flexibility to refocus resources on these kinds of projects in a timely manner

6. Commit to the goal and develop a process to ensure effective collaboration between all stakeholders (as discussed in the previous section).

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7. Recognize that PERD **also needs to focus on the knowledge required** for regulation, and **for minimizing adverse environmental impacts. However, research in these areas should not be** done unless the work is in place to create an economic development in the first place.

8. Recognize that PERD can play a role in preserving critical **knowledge and expertise, but this shouldn't drive the program.**

By definition, the emphasis of PERD Task **6, has to be in advancing** knowledge and technology through research. Therefore, it is appropriate that the existing committee structure be preserved. These are:

6A - Engineering and Geoscience

6B - Environment

6C - Transportation

However, it is recommended that key members of these committees also serve on a series of Task Forces which are focused on regional scenarios. It is also recommended that these Task Forces have representation from the key stakeholders. These would include the regional boards and governments, industry operators, and federal agencies with the appropriate spectrum of mandates. These Task Forces would be working groups who would be required to be completely knowledgeable about the oil and gas scenarios relevant to their region, and who would identify, select and monitor the research and technology thrusts needed to enhance the economics of regional scenarios. They would have access to economic modeling so that they could fully understand the potential benefits of these research thrusts and set priorities accordingly. They would be responsible for achieving research collaboration with industry and others as well as communicating the results of the work. Each Task Force would have a secretariat and would need a leader who would need to devote at least 50% of their time to the assignment.

Based on the results of this study, it is recommended that three Task Forces be created at this time; these are:

1. Task Force on Beaufort Oil Development

This would focus initially on the two scenarios which this study has shown to have the potential to be economic without the discovery of additional reserves. These are: (a) A tanker development, to produce already discovered offshore oil on a seasonal or year-round basis. (b) A small pipeline development also to produce offshore oil at 35,000 Bbl/day. The Task Force could also recommend research to lower the cost of exploration, which will ultimately be needed to support larger oil developments.

2. Task Force on Grand Banks Oil Development

This would focus primarily on floating production scenarios especially those relating to the smaller fields.

3. Task Force on Nova Scotia Gas Development

This would focus on technology to support the economic development of gas in the Sable Island region.

it is suggested that a matrix structure as shown in Figure 24 be adopted. The scenario Task Forces would report to the Strategic Planning and Steering Committee, but would need to closely communicate with the Technical Committee, who would still retain their responsibility to approve and allocate budgets. However, it is suggested that about 80%?? of the projects submitted to the Technical Committees be from the Task Forces. Very little, if any, of the budget should be allocated to projects not requested by the Task Forces. The Technical Committees' main function will be to ensure that appropriate synergies and avoidance of duplication are achieved in technical areas common to the various scenarios. Technical subcommittees can also exist as appropriate, in order to achieve a deeper technical focus and to advise the Task Forces and Technical Committees of innovative possibilities.

Task Forces will not necessarily be permanent fixtures, and their existence will be determined by the Steering Committee. They will be formed only for those regional scenarios which have a reasonable chance of being economic with the current price outlooks. Their aim will be to conduct research, which, as a first priority, is to create wealth through economic development of Frontier hydrocarbons.

Innovative science and technology which could lead to a break-through relating to scenarios currently without a Task Force, could be approved by the Technical Committees. But, this would have to be clearly identified as such, and, if possible, some scoping economics would be done to identify the size of the prize for the Nation.

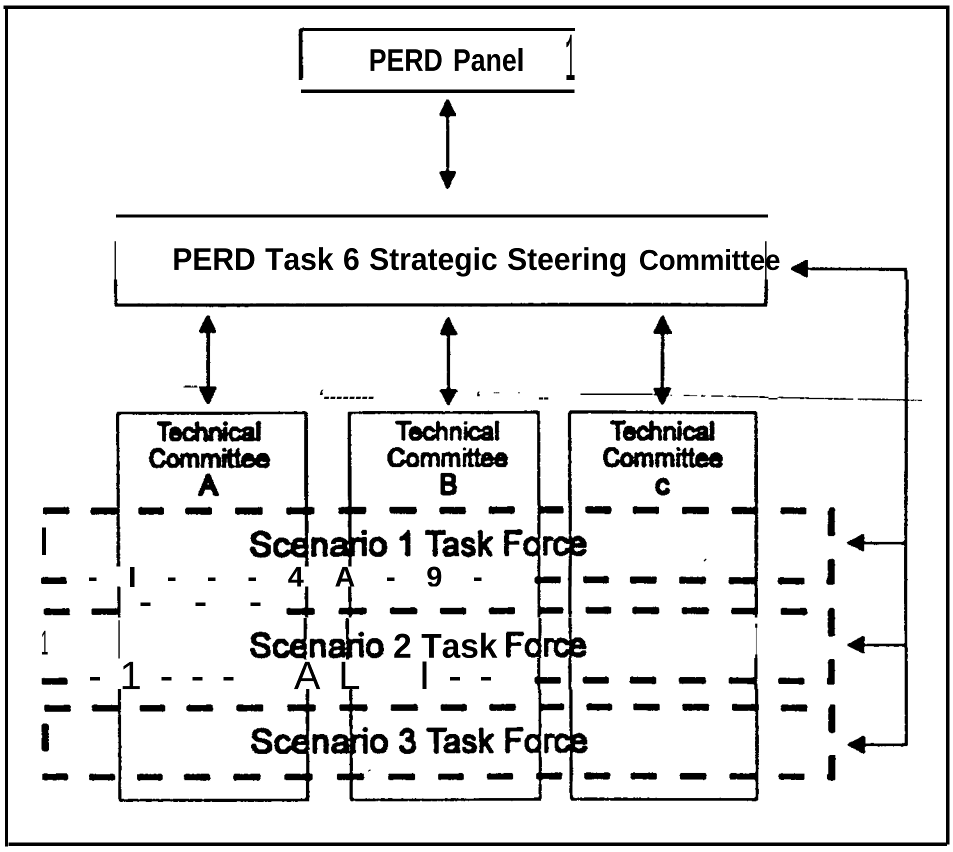

Figure 24

All this may sound somewhat bureaucratic, but, if all those involved have a common vision of what can be achieved, then, we believe, that the recommended structure and process can work smoothly and be a positive experience.

It is not the intention of these recommendations to belittle the work that PERD has done, and will continue to do, on knowledge required for regulation and environmental impacts. Indeed, it is critical that this knowledge be generated for each of the scenarios being pursued, and regulatory representation on the Task Forces will be essential. But, it is recommended that work whose only rationale is for regulation and environmental impact assessment should only be approved if the related scenario is already economic, or if sufficient R & D is in place with a high probability of ultimately achieving an economically attractive development.

Concluding Remarks

Although activity in many of Canada's Frontier regions is at a low point, the potential exists for the Frontiers to be economically developed, thereby creating benefits for the Nation. However, it cannot be assumed that oil and gas prices will eventually rise to the point where the Frontiers are economically attractive. On the other hand, this study has shown that focused research resulting either in cost reductions in key areas or in minimizing downside risks can create economically robust development scenarios.

It must be emphasized that the objective of this study is not to promote specific Frontier development projects. Nor is it to persuade operators and governments to start planning for specific developments. The scenarios were examined solely to help focus research on areas that could lead to, or enhance, economic developments. And conversely, to help avoid putting research effort into areas which have little value in enhancing Frontier resources.

It is also worth noting that other enhancements, in addition to improved technology, can have significant effects on economics. For example, a smoothing and guarantee of transportation tariffs can help to trigger the first development in a region and stimulate exploration.

The attractiveness of aligning research to development scenarios which can be made economically attractive through improved technology is that progress can be made towards economic development without committing to large expenditures. Yet, by involving key stakeholders in planning and conducting the R & D, a common purpose and coordination of effort is maintained.

The economics for this study are not precise, and could probably benefit from better inputs for some of the costs. On the other hand, the approach used has the attractiveness of comparing a variety of scenarios on a common basis. Also, the economic software used has the advantage of being very flexible and efficient, and variations on specific scenarios can be analyzed very quickly and efficiently.

This study has been of limited scope and much work remains to be done. Not all the specific research initiatives that will be necessary have been spelled out. This, we believe, is appropriate for two reasons. First, other experts are more knowledgeable than we in several of the technology areas and can, therefore, better specify the specific R & D required within the general research thrusts (This is particularly true for geoscience R & D opportunities). Second, as recommended, the proposed Task Forces working together with the Technical Committees, have the ultimate task of defining the R & D program for the selected scenarios.

It is possible that before specific R & D projects can be specified in -- -- some areas, additional scoping studies will need to be done to understand the costs in more detail. For it is only by understanding the impact on costs (and hence economics) that the value of a particular research project can be assessed. It will be up to the Task Forces to recommend sponsoring such studies by PERD.

In conducting this study, some selectiveness has been exercised in order to avoid over-dilution of the effort. For example, the West Coast, Hudson's Bay and Georges Bank regions have been left out, and there are several reasons for this. One is that moratoriums are in place on West Coast and Georges Bank activities for environmental reasons. There is little point in devoting limited research funds to regions which do not want to see oil and gas activities. Second, the physical environmental conditions on the West Coast and Georges Bank are conventional offshore with no ice problems, and there is little need for technology advancements to unlock any significant discoveries which may occur. Third, the Hudson Bay region has little potential for significant discoveries.

The benefits to Canada in adopting the approach recommended in this study are more than just creating wealth from its indigenous resources, Canada has extensive "Frontier regions" and the ability to operate and develop improved technology for its Arctic and offshore regions is an issue of strategic and economic importance. Canadian organizations have already acquired considerable expertise in remote operations and engineering. Some of this expertise is now being tapped for applications in other parts of the world, such as Siberia. To maintain and enhance this expertise, a domestic focus is desirable. This can be achieved if the recommendations made in this report are adopted.

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Also, acknowledged are the valuable inputs and advice received from the numerous organizations, listed in Table 22 who were consulted during the study. This study would not have been possible without these valuable inputs. However, the opinions and recommendations given in this report are those of the authors and do not necessarily represent the views of either any of the organizations providing input or of the Federal Panel on Energy R & D.

Organizations Contacted for Input to the Study

The National Energy Board

Energy Mines and Resources, Canada

The Geological Survey of Canada

Indian and Northern Affairs, Canada

The Canadian Coast Guard

The Government of the North West Territories

Department of Energy, the Government of Newfoundland and Labrador

Canada - Newfoundland Offshore Petroleum Board

Canada - Nova Scotia Offshore Petroleum Board

The Arctic Institute of North America

The Canadian Association of Petroleum Producers

Amoco Canada Petroleum

Canarctic Shipping

Canadian Marine Drilling

Chevron Canada Resources

Gulf Canada Resources

Hibernia Management and Development Company

Husky Oil

Imperial Oil Resources

Interprovincial Pipeline Co.

Kvaerner Engineering as.

Mobil Oil Canada

Panarctic Oils

Petro Canada

Polar Delta Project

Shell Canada

AKAC Inc

B. Wright& ASSOC.

Table 22

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