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OIL AND GAS RESOURCES OF CANADA 1983

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GLOSSARY OF TERMS

allochthonous: Formed elsewhere than its present place.

basement: The undifferentiated complex of rocks that underlie the rocks of interest in an area.

basin analysis: The study of all aspects of geoscience and their interrelationships for a depositional basin.

bathyal: The environment of deposition in deep water between 200 and 2000 metres now largely confined to the outer continental slopes.

bioherm: A moundlike or reeflike mass of rock built up by sedentary organisms.

biostrome: A distinctly bedded extensive mass of rock built by, or made up of, the remains of sedentary organisms.

bitumen: A generic term applied to a solid composed principally of a mixture of hydrocarbons substantially free of oxygenated bodies.

conventional oil and gas: Oil and gas wholly or in part recoverable from a well using standard techniques.

craton: A part of the earth's crust that has attained stability, and has been little deformed for a prolonged period.

depocentre: An area or site of maximum deposition.

diapir: A dome or anticline in which the overlying strata have been ruptured by the intrusion of underlying plastic materials.

epeirogenic: Primarily vertical movements (up or down) of large parts of continents.

epicontinental sea: Situated on the continental interior.

eustatic: Pertaining to worldwide changes of sea level that affect all oceans.

evaporite: A nonclastic sedimentary rock composed primarily of minerals produced from a saline solution as a result of evaporation.

exploration play: A group of similar exploration prospects postulated or proven to contain oil and, or natural gas, i.e. a group of genetically related prospects or pools. A play may contain both discovered pools and conceptual prospects as yet undrilled.

facies: The aspects, appearance, and characteristics of a rock unit, usually reflecting the conditions of its origin.

listric: A usually concave upward surface of fracture.

melange: A body of rock characterized by the inclusion of fragments and blocks of all sizes, both local and exotic, embedded in a sheared matrix.

miogeocline: A prograding wedge of shallow water sediment at the continental margin or along a geosynclinal seaway.

natural gas liquids (NGL's): Hydrocarbons generally produced in association with natural gas, and recoverable as liquids, including propane, butanes, and pentanes plus.

orogenic: Related to the process of mountain building.

palinspastic: The process of restoring features to their original spatial positions prior to deformation.

paralic: Pertaining to intertongued marine and continental deposits laid down on the landward side of the coast or in shallow water subject to marine invasion.

prodelta: That part of the delta that is below the effective depth of wave erosion.

prospect: A geological configuration (e.g. a structure defined geophysically)conceived to have trapped petroleum that forms a target for drilling.

salt pillow: An embryonic salt dome rising from its source bed, still at depth.

sebkha: A supratidal environment of deposition formed under arid conditions on restricted coastal plains just above high tide level.

subcrop: A subsurface contact that describes the areal limit of a formation beneath an unconformity.

subduction: The process of one lithospheric plate descending beneath another.

syntectonic: A geologic process or event occurring during a period of tectonic activity.

terrane: A crustal fragment characterized by a distinctive, laterally persistent stratigraphic record that differs from the coeval records in neighboring terranes, from which it is separated by major faults and, or structurally complex zones.

turbidity flow: A tongue-like flow of dense sediment laden water moving down a slope.

vesicles: Cavities of various shapes in lava formed by the entrapment of gas bubbles during solidification.

vug: A small cavity in rock commonly lined with crystals.

ILLUSTRATIONS

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SUMMARY

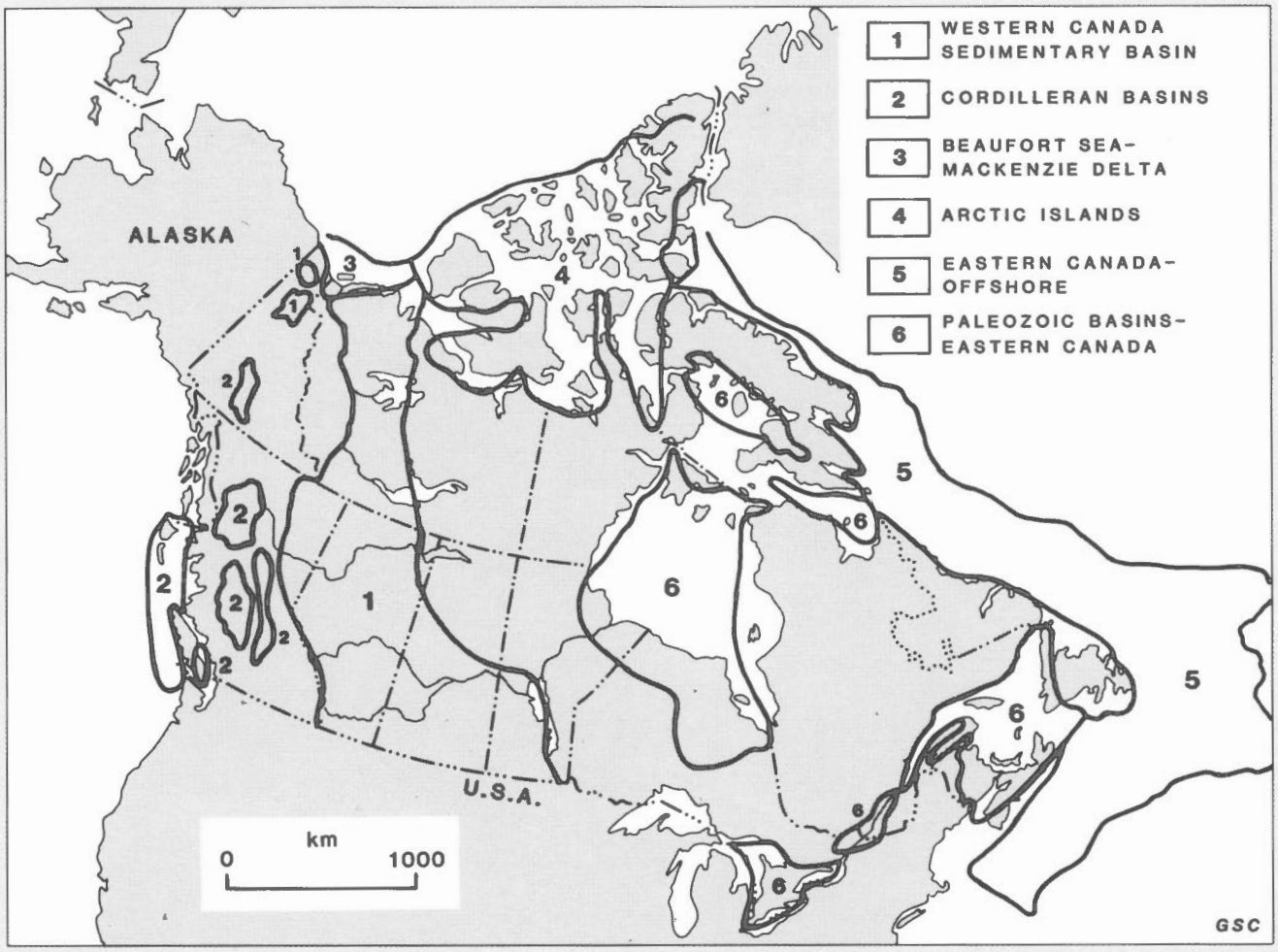


Figure 1.1 Canada's petroleum regions

The oil and natural gas resources of Canada are evaluated on a systematic basis by the Geological Survey of Canada. This report summarizes the current estimates of quantities of oil and natural gas that inferred to exist but are not yet discovered. The analysis of resources is made for each of Canada's six petroleum regions (Figure 1.1), addressing both conventional and non-conventional resources. The present report, which replaces "Oil and Natural Gas Resources of Canada — 1976" published by Energy, Mines and Resources in 1977, contains major revisions and new estimates for most parts of Canada. The estimates of potential resources, those inferred to exist but as yet undiscovered, prepared by the Geological Survey of Canada are supplemented by estimates of reserves, or discovered resources, provided by the Canada Oil and Gas Lands Administration for frontier areas; and by the National Energy Board for the Western Canada Sedimentary Basin.

Conventional Resources

Canada is well endowed with oil and gas resources. Current estimates of remaining established reserves of oil are 754 million cubic metres, and of gas 2111 billion cubic metres, all located in Western Canada. To these can be added the best current estimates of discoveries in frontier areas, which increases the discovered portion of Canada's conventional resources to an estimated 1219 million cubic metres of oil and 3005 billion cubic metres of gas. Estimates by region, summarized in Table I, indicate that significant oil and gas reserves have been identified in Eastern Canada Offshore and in the Mackenzie Delta-Beaufort Sea regions. Important gas reserves also have been discovered in the Arctic Islands region.

Estimates of oil and gas potential are prepared using a probability methodology that expresses the range of quantities that may exist, along with the probability or confidence level associated with different parts of that range. Throughout the report, the estimates of potential are expressed at three levels of confidence, as in Table I. The values contained in Table I are also displayed in figures 1.2 and 1.3 which permit an easy comparison of the relative potential estimated for each region. The figures indicate that the potential for

oil is greatest in the Eastern Canada Offshore region, followed by the Beaufort Sea-Mackenzie Delta region, both areas having greater potential than Western Canada. Gas potential however, is estimated to be more evenly distributed in four regions.

Non-conventional Resources

In addition to the conventional resources, Canada is more richly endowed with non-conventional oil and gas resources than most countries. These resources dwarf the conventional category in terms of total quantity or in-place reserves, and have the added advantage of already having been discovered. The costs associated with their development, and the need for new cost-reducing extraction technology do not permit reliable estimates of recoverable reserves in the same context as those shown in Table I, but remaining established reserves of synthetic crude oil are estimated to be 3860 million cubic metres. Also, not listed in Table I, and sharing in the uncertainty of costs and new technology, is potential that may result from enhanced oil recovery applications to Western Canada reserves. This process is estimated to have potential for an additional 500 million cubic metres of oil as an average expectation.

Supply Considerations

Canada's future oil supply will derive from some mix of conventional, frontier, heavy oil and non-conventional sources. The proportion of each will depend on many factors including comparative economics, developments in technology, and investment strategies. Figure 1.4 is an attempt to illustrate Canada's currently identified total oil resources as a possible inventory from which future supply may be selected. No quantity values are identified for segments in the figure because reliable estimates of recoverable oil from in-situ oil sands development and tertiary recovery methods in heavy oil are not available and some arbitrary, probably conservative, recovery factors have been assumed. The proportions are adequate however to compare short term supply options at least in terms of what is already known to exist. A decade of continued exploration may modestly increase the Western Canada segment, and could easily double the size of the "Frontiers" segments. However, the oil resources associated with oil sands will continue to dominate the inventory in a quantitative sense. Figure 1.4 is of course incomplete and potentially misleading in that the economic viability of each segment can vary by orders of magnitude — a factor not considered in the diagram, and beyond the scope of this study.

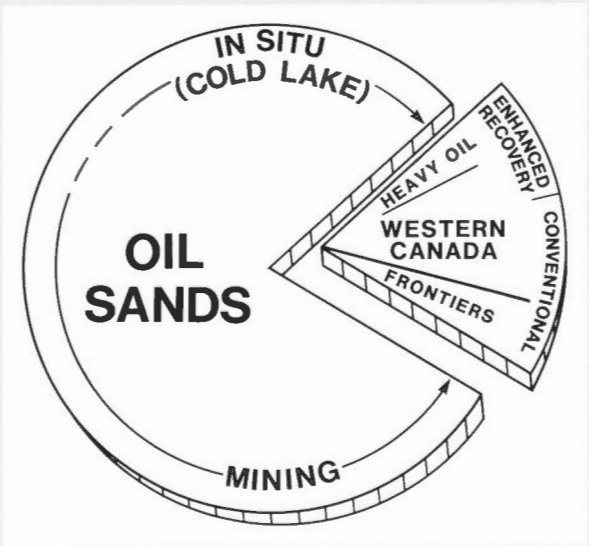


Figure 1.4 Canada's identified oil resources

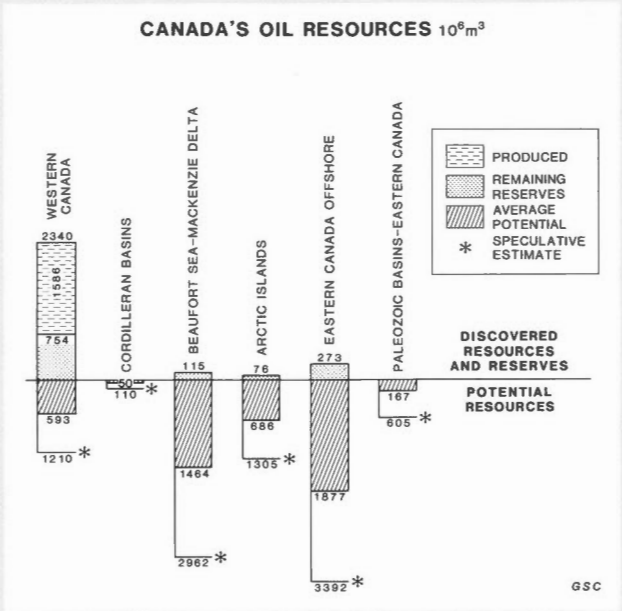


Figure 1.2 Conventional oil resources of Canada

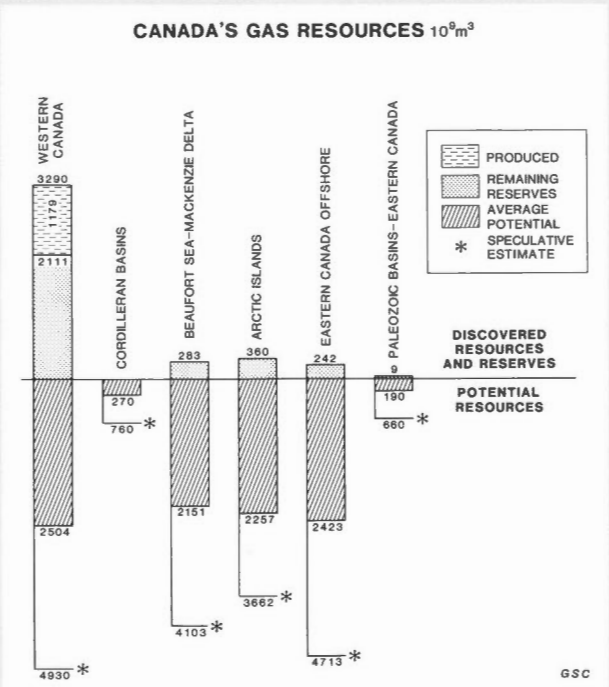


Figure 1.3 Conventional gas resources of Canada

TABLE I CONVENTIONAL OIL AND GAS RESOURCES OF CANADA

	RESERVES AND DISCOVERED RESOURCES	POTENTIAL		
		High Confidence	Average Expectation	Speculative Estimates
Oil $10^6 m^3$ (Recoverable)				
Western Canada Sedimentary Basin	754	234	593	1210
Cordilleran Basins	—	—	50	110
Beaufort Sea-MacKenzie Delta	115	307	1464	2962
Arctic Islands	76	316	686	1305
Eastern Canada Offshore	273	512	1877	3392
Paleozoic Basins - Eastern Canada	0.8	20	167	605
TOTAL	1219	*1486	4837	*8995
Gas $10^9 m^3$ (Recoverable)				
Western Canada Sedimentary Basin	2111	1544	2504	4930
Cordilleran Basins	—	40	270	760
Beaufort Sea-MacKenzie Delta	283	871	2151	4103
Arctic Islands	360	1100	2257	3662
Eastern Canada Offshore	242	725	2423	4613
Paleozoic Basins - Eastern Canada	8.8	46	190	660
TOTAL	3005	*4342	9795	*18285

* These numbers do not add arithmetically but must be summed using statistical techniques.

CONCLUSIONS

Conventional Resources

Canada's potential oil and natural gas resources are large and could ensure self-sufficiency if means can be found to convert a significant portion of them into economic reserves. The potential for future discovery is greater in the frontier regions than in western Canada. This is due to the degree of exploration maturity of the Western Canada Sedimentary Basin.

The portion of these resources that is, or will be, commercially viable depends on prevailing economic conditions as affected by technological progress in development, production and transportation. To date there has been no consensus regarding specific development, production and transportation systems suitable for frontier discoveries, particulary for offshore areas. This has hampered the ability to estimate the contribution that frontier resources can make to future Canadian energy supplies. The Department is working towards providing estimates that can be used with a reasonable degree of confidence.

The pace of exploration, and therefore the rate at which frontier resources are discovered, will be affected by factors that include exploration success; expectations regarding market prices, development and operating costs; prevailing fiscal regimes; technological progress; and successful commercial exploitation of discoveries already made. Lead times from discovery to commercial development are long in frontier regions and it is unlikely that large-volume frontier production will be available to Canadian markets until the 1990's.

For the balance of this decade therefore, domestic oil supply will have to depend primarily on western Canada reserves. Infrastructure already in place in this area ensures that newly-found conventional reserves can be quickly placed on production, however more intensive exploration efforts will be needed to accelerate discovery. Enhanced recovery of existing light and medium crude oil reserves and of heavy crude oil can, as well, make a substantial contribution to supply over this period.

Oil supply beyond 1990 will likely include production from frontier discoveries in the East Newfoundland Shelf, Arctic and the Beaufort Sea regions. Given the appropriate economic climate, additional in-situ oil sands projects, surface mining oil sands plants, heavy oil and an increasing quantity of enhanced recovery supply can also be viewed within this time-frame, as well as a continuing contribution from conventional oil from the Western Canada Basin.

In addition to development of oil deposits already taking place in the Mackenzie Corridor, pipeline access to the northern frontiers would open other oil resources of the Mackenzie Corridor to southern markets.

Gas potential estimated in all frontiers plus western Canada, in addition to present reserves, indicates an assured supply. These resources should meet current requirements as well as expansions of Canadian gas markets for the foreseeable future. This will, of course, require development investments to maintain and expand delivery capacity from western Canada.

Major current limitations on frontier gas development are high development, operating and transportation costs, and lack of markets. In addition, remote frontier projects face technological and environmental hurdles.

Non-Conventional Oil Resources

The future mix of non-conventional and conventional resources in supplying domestic energy requirements will depend on the relative costs of exploration, development, operation and delivery to market.

Canada has a large potential supply of oil from heavy oil reservoirs and oil sands deposits. These resources represent a known source of supply, probably exceeding conventional oil resources in terms of quantity ultimately producible. Available upgrading technology together with development and operating costs are the limiting factors in bringing these supplies to the Canadian market. Although the technology for heavy oil and bitumen extraction exists at this time, a full realization of the potential from in-situ recovery and heavy oils will require advances in upgrading technology. Small scale upgrading projects could allow technology demonstration and improvements and hopefully will lead to larger scale projects.

INTRODUCTION

FEATURES

INTRODUCTION

This document replaces the "Oil and Natural Gas Resources of Canada 1976", E.M.R. Report EP77-1. Since 1976 additional data and information regarding the geology of Canada's petroleum basins has been assembled and analysed. The current report contains revisions and new estimates for many regions based on this improved data base.

Oil and natural gas remain the major sources of Canada's primary energy requirements. Although requirements for these fuels have been reduced through energy conservation and efforts to promote substitutes for oil, this dependence will continue. Despite the vigorous exploration effort since 1976, Canada has seen a decline in the amount of petroleum in actual reserves. Major new discoveries have been made in the frontier regions of Canada but because of their nature and current economics their commercial development will be delayed a number of years. Also, changes in the world economic climate have deferred anticipated production from the non-conventional resources, particularly major oil sands and proposed heavy oil projects.

Thus there remains as a major requirement the 'need-to-know', in ever increasing sophistication, the nation's endowment of petroleum resources. A series of questions can be formulated concerning these resources which are fundamental to the planning and decision making process within the investment community and are essential for rational government policy consideration.

1. How much oil and gas is likely to exist in Canada?
2. What is the geographic distribution of these oil and gas resources among frontier basins and the established producing areas?
3. What degree of confidence can be attached to these estimates of petroleum resources?
4. What are the likely rates of discovery and development of production capability from these resources?
5. What is the likely cost of developing and delivering these resources to the market place?

This report deals directly with the first three of these questions and provides a starting point for analysis of the last two.

To quantify Canada's oil and gas resources potential, the Geological Survey of Canada has developed a methodology in which cummulative probability curves are produced for oil and gas occurrences for various basins, regions or other identifiable areas. The curves are drawn with the knowledge of actual occurrences into which geological judgment is incorporated.

The first phase of the process is the identification of the exploration plays present in a given area. A play consists of a group of prospects and/or discovered fields having common geological characteristics such as source rock, trapping mechanism, etc. Because each factor may vary widely in favourability for hydrocarbon accumulation, their combination in a play provides the possibility for a wide range of values. A play may contain both oil and gas together or separately.

The hydrocarbon potential of individual exploration plays within a sedimentary basin is summed using appropriate statistical techniques.

Estimates prepared in this manner by the Geological Survey of Canada, for six separate geological-geographical regions of Canada are presented in the following pages.

Scope

This report is a summary of the Geological Survey of Canada's current analysis of Canada's oil and gas resources. The summary is drawn from the on-going petroleum resource evaluation program in which the detailed appraisals of individual basins or regions are periodically reviewed. These detailed reviews, are released usually as Open File Reports of the Geological Survey. They contain as many as possible of the petroleum geology data and information that were used in the preparation of estimates. The resource evaluation activity draws extensively from the on-going Basin Analysis Program within the Geological Survey of Canada. This program includes the recording of specialized technical data to produce a variety of reports that synthesize the state of knowledge at a given time.

The style of the summary report is designed to provide current estimates of resources in juxtaposition with brief and generalized comments on the regional setting. Comments are also offered concerning opportunities for future discovery. Those who require more information on any given area are referred to the Open File Report series.

Petroleum resource evaluation activities of the Geological Survey of Canada are focussed primarily on the undiscovered or potential components of conventional oil and gas resources, which is the major emphasis of this report. For the convenience of readers, the authors have compiled data on unconventional resources from the literature and provincial government agency publications to supplement the Survey's limited studies in this area.

Terminology

The word **resource** as used here includes all oil and gas accumulations known or inferred to exist. **Reserves** comprise that portion of the resource that has been discovered. The word **potential** describes that portion of the resource inferred to exist but not yet discovered. The terms **potential** and **undiscovered resources** are thus synonymous and can be used interchangeably.

The expression **established reserves** is used to describe those reserves which on the basis of identified economic considerations and within a specified time frame, are recoverable with a high degree of certainty from known reservoirs. Because reserves discovered in frontier regions are not fully delineated, and have uncertain economic viability, they do not fit the "established" criteria, and here are expressed as **best current estimates of discovered resources.** The term **remaining reserves** is used here to indicate that remaining portion of a recoverable accumulation not yet produced.

Within this report, gas values given are for marketable or pipeline gas; oil values are given in the SI equivalent of stocktank barrels. For convenience, the unmodified terms **reserves** and **potential** should be read as equivalent to recoverable reserve and recoverable potential. The expression **in-place reserve** is used (in the Non-Conventional Resources chapter) to represent the total volume of oil or gas in a reservoir without consideration of what portion may be recoverable.

Data Base

The Department of Energy, Mines and Resources has had a petroleum resource evaluation program for the past ten years. As data and methodology have evolved the Geological Survey of Canada has prepared successive estimates of Canada's oil and gas resources. The estimates contained in this report are based mainly on data available to the end of 1982 although some information

resulting from 1983 exploration programs has been incorporated.

The estimation of the potential of any region depends upon data supplied by industry and government scientists and involves both subjective and objective approaches. Most of the types of data normally used by industry in analyzing exploration plays were available for the preparation of the oil and gas estimates presented here. Data are evaluated in the light of new concepts and hypotheses and in the light of oil and gas occurrences throughout the world.

A resource analysis depends to a considerable degree on the accumulated knowledge concerning the overall framework of the earth's crust, in particular the various sedimentary basins throughout Canada. Such data include the interrelationships of rocks in various areas as well as their geometric configuration. In assessing the potential of an area, the first step is to identify major regions or sedimentary basins of different character. Specialized data are collected then for each region. For example data derived by specialists in geochemistry from the study of the organic material contained in sedimentary rocks provide particularly useful information on the extent and quality of the source rocks within which hydrocarbons may be generated. Such data are fundamental to building an understanding of gas and oil occurrences in a region. Geophysical data such as reflection seismic sections provide a better understanding of the shape, size and character of known and potential oil and gas accumulations. Information on past exploration activity and statistics on any hydrocarbon production is also used in making estimates.

Methodology

The methodology used in petroleum resource evaluation was developed initially to provide the capacity to understand the country's petroleum resources, make economic analyses and project the amounts and costs of future supply from various regions. Initially, the concerns were with the resources of frontier regions which were the least understood geologically. Through time, the concerns have moved to the more conventional resources of Western Canada and, more recently, to quantities recoverable through enhanced recovery processes. As the requirements have changed, so has the methodology. Starting initially from rather simplistic volumetric calculations, the Survey's approach has evolved to what can now be described briefly as a probabilistic methodology conducted at the exploration play level, incorporating both objective data and informed geological opinion. A few years ago, this would have been referred to as the Monte Carlo approach. However, methodology has now advanced well beyond the Monte Carlo stage with more rigorous and more powerful mathematical procedures being incorporated into the system. A characteristic of the approach that remains, however, is the display of estimates in probability terms, usually expressing a range of possible values rather than a single number. Figure 2.1 is an example of a typical curve of estimates which represents the distribution of all possible estimates, given the ranges of all input variables. The curve shown indicates as a minimum expectation that more than 65 million cubic metres of oil are estimated to exist; that on average more than 150 million

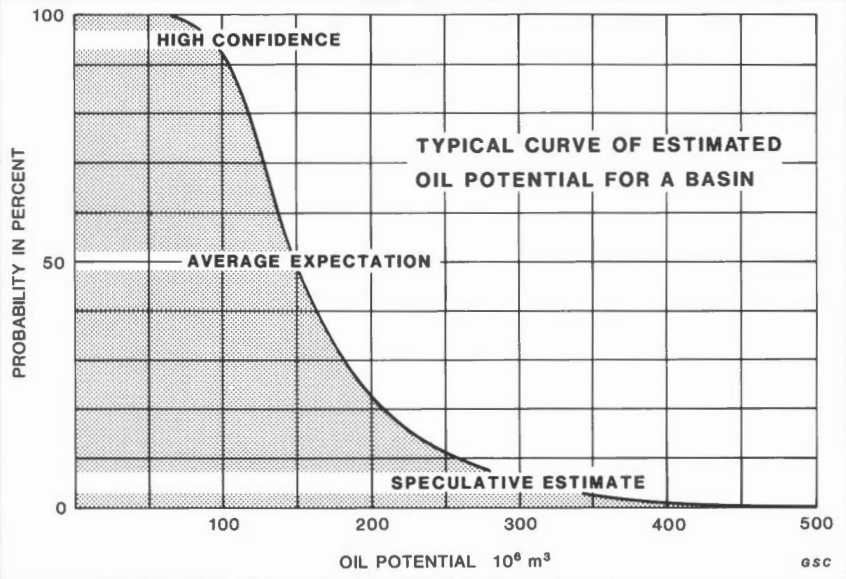


Figure 2.1 Estimate of oil potential for hypothetical basin (cummulative percent probability distribution). Bars indicate values cited in various resource tables

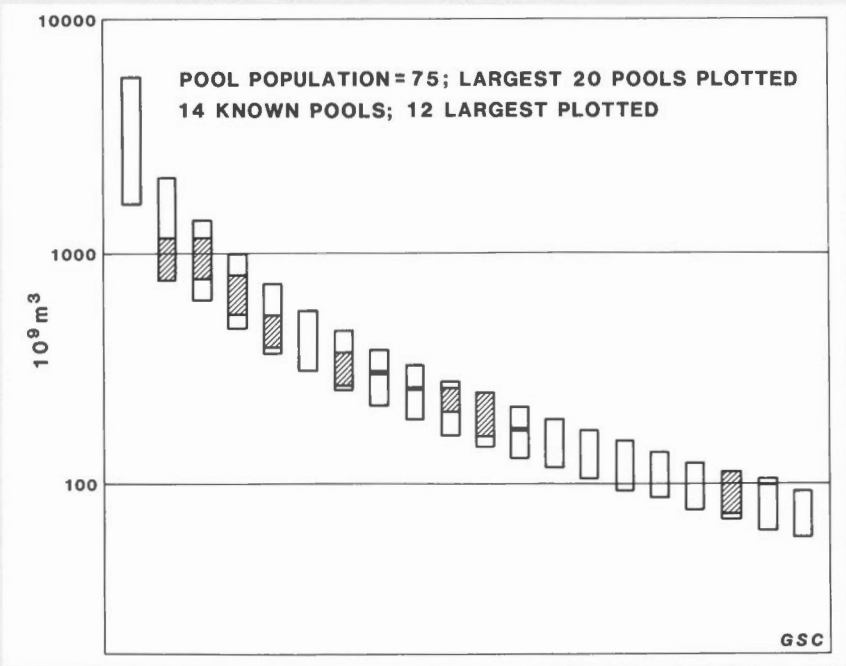


Figure 2.2 Hypothetical pool sizes of play ranked by size. Boxes represent 25 to 75 percent confidence limits. Shaded boxes represent known discoveries

cubic metres may exist; and there is no expectation of more than a value of 480 million cubic metres. As in the case of most real examples, this distribution curve is significantly skewed. Therefore in totalling a number of such curves, only the average expectations can be arithmetically summed. Statistical techniques must be used at other probabilities. There is only one real value for the potential of the basin of course, but it will not be known until the basin is totally explored and produced. The estimate curves change as new data become available and the range of possible values is reduced. For convenience in the report that follows, the full curves are not reproduced, but the three values indicated in Figure 2.1 are tabulated as representative of the current estimates.

In addition to estimates of basin potential, the operating methodology can produce an array of hypothetical pools with attached reservoir characteristics consistent with the input geology and data. One such array is shown in Figure 2.2 in which each bar represents the 25 to 75 percentage probability value for a single pool. This technique provides a useful comparison of predicted pool sizes against the actual results of exploration. In the example given, the discovered pools fit the prediction and suggest that the largest pool has not been found.

The same sets of hypothetical pools can be used also to simulate the results of exploration in terms of cumulative discovery per unit of exploratory drilling. The example shown in Figure 2.3 indicates that about 50 wells would be required to discover 15 billion cubic metres of gas in the basin illustrated. This type of data is particularly useful in the comparison of basinal or regional expectation and as a test of prediction against discovery history.

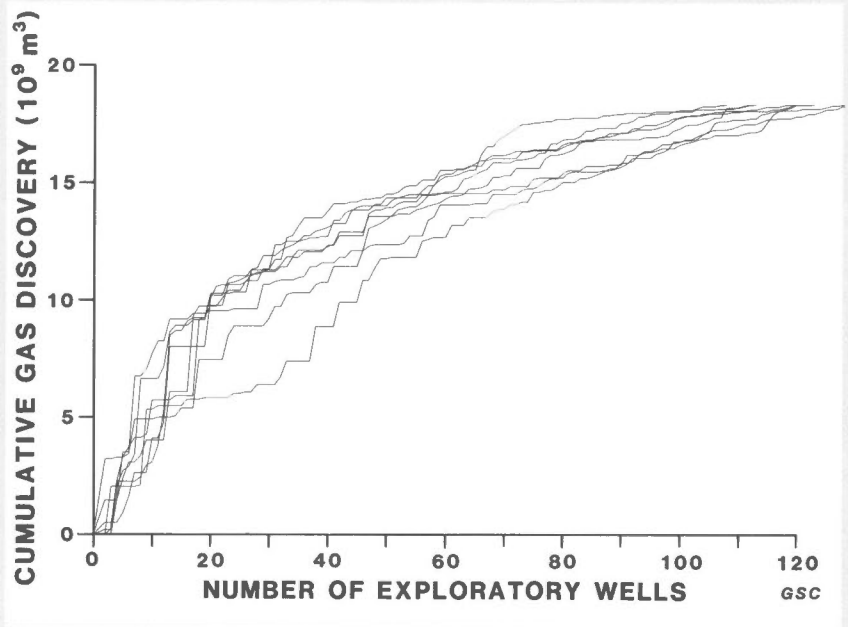


Figure 2.3 Hypothetical discovery model. Each line represents one computer simulation

Economic Considerations

It must be emphasized that these estimates of potential resources, described in terms of probability, are not to be regarded as reserves. In no sense can the estimates be regarded as assured supplies. Firstly, at the time of preparation of the estimate perhaps only a portion of the total resources had been discovered. Secondly, a complex set of economic factors combined with national priorities will determine future rates of discovery, development and production. Investors must be able to anticipate a competitive return, taking into consideration project specific risks. These include reservoir area, well productivity, distance from material supplies, labour, cost of environmental protection and many others. Some other factors include availability of markets at prices adequate to cover the costs of field development and operations. Depending on the point of sale, transportation, particularly from the frontier, can be a significant cost which the resource developer must be able to absorb out of project returns.

From a national perspective, sufficient benefits must be available from resource development, irrespective of private profitability, to justify the allocation of resources to their exploitation. In this regard, a number of quantifiable and non-quantifiable factors need to be considered. For example, environmental impacts can represent costs to Canada, whereas demonstration of technology with the associated research and development activities which take place can provide other significant benefits for Canada. Although such costs and benefits may not, strictly speaking, be of concern to the private investor they are very much a concern in managing publicly owned resources.

In Canada's conventional producing areas, where a history of development and production is present, assessment of overall economic viability and environmental impact is less complicated in comparison to frontier regions. This is not to say that such assessments can be routinely prepared for major projects in conventional regions. Such decisions require a good deal of effort on the part of the private sector, federal, provincial, municipal governments, regulatory bodies and other interested parties. In frontier regions, however, estimates of capital costs, operating costs, and transportation costs are tentative, bordering on speculative, at this time. Canada has no experience in commercial production and transportation from these areas, which are on the technological frontier in a harsh and sensitive environment.

The Department of Energy, Mines and Resources expects to continue to assess the economics of commercial oil and gas development in various areas of resource potential in an attempt to estimate that portion of potential resources which is likely to fall within the commercial threshold and contribute to Canada's future petroleum supplies. The resource estimates presented in this paper represent a basic data base for such work.

Acknowledgements

The authors have freely drawn on the work of a large number of geologists and on the published literature. Particularly useful sources of information have been supplied from the offices of the Canada Oil and Gas Lands Administration (COGLA), the National Energy Board (NEB), and individuals of the Institute of Sedimentary and Petroleum Geology (ISPG) and Atlantic Geoscience Centre (AGC), Divisions of the Geological Survey of Canada. Special thanks go to R. Conn of the Energy Sector of Energy, Mines & Resources who supplied the comments on economic considerations.

Completion of the report would have been impossible without the active participation of L. Mac Lachlan as production editor, and his staff of draftsmen, particularly J. W. Thomson and W. P. Vermette. Special thanks go to A. Foo who was responsible for the word processing.

PETROLEUM REGIONS OF CANADA

FEATURES

PETROLEUM REGIONS OF CANADA

The oil and natural gas resources of Canada are evaluated on a systematic basis by the Geological Survey of Canada. This report summarizes the current estimates of quantities of oil and natural gas that already have been discovered along with those quantities that are inferred to exist but are not yet discovered. The analysis of resources is made for each of Canada's six petroleum regions (Figure 3.1) addressing both conventional and non-conventional resources with the emphasis on quantifying the undiscovered resources.

Canada is well endowed with natural resources, including oil and natural gas, because of the complex and varied nature of the geology of its landmass and adjacent flooded continental borders. Three major geological settings comprise the framework of Canadian geology. The most complex and oldest rocks are exposed in the vast central region known as the Precambrian Shield, and underlie the structurally stable region known as the craton. Although stable, the craton was covered by shallow seas throughout much of geological time. A thin veneer of sediments deposited in these seas on the craton and over its margins constitutes the sedimentary basins of Canada. Interactions of global tectonic plates resulted in the deformation of these sediments to produce mountain chains around most segments of the edge of the craton. The habitat of oil and natural gas exists primarily in the sedimentary cover of the craton and its margins as well as in those portions of the deformed rocks that have not exceeded the physical limits on preservation of contained hydrocarbons.

Four geological parameters; age (Figure 3.2), facies, structure, and thickness allow the organization of the sedimentary basins into six major petroleum regions. On the following pages of this chapter an attempt is made to inform the reader of the significant characteristics of each of these regions. For each region the initial pages carry a summary of the estimates of the discovered and undiscovered resources. For the reader interested in more detail concerning the geological setting of potential accumulations, a descriptive section is provided for each major element that comprises the region. These sections represent the synthesis of more extensive analyses that have been developed within the Geological Survey of Canada.

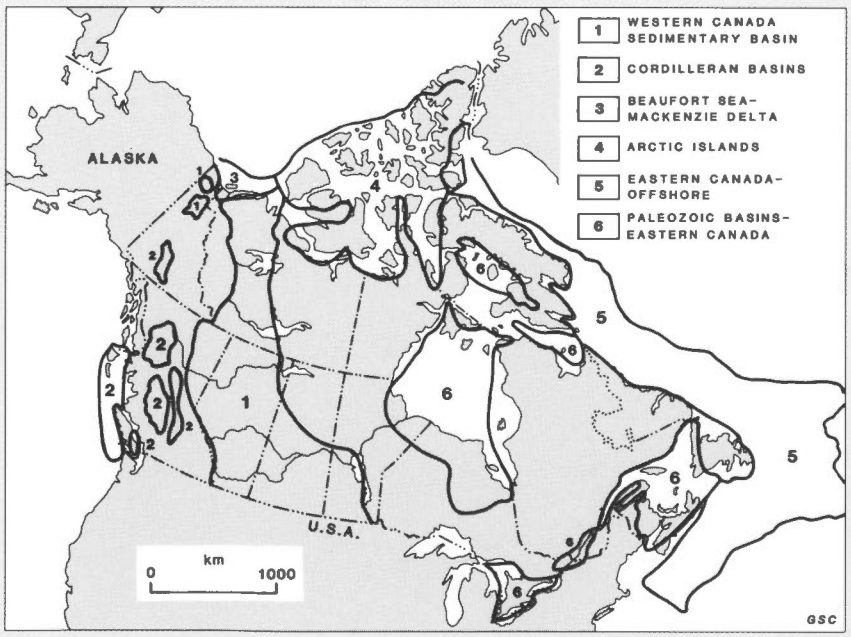


Figure 3.1 Canada's petroleum regions

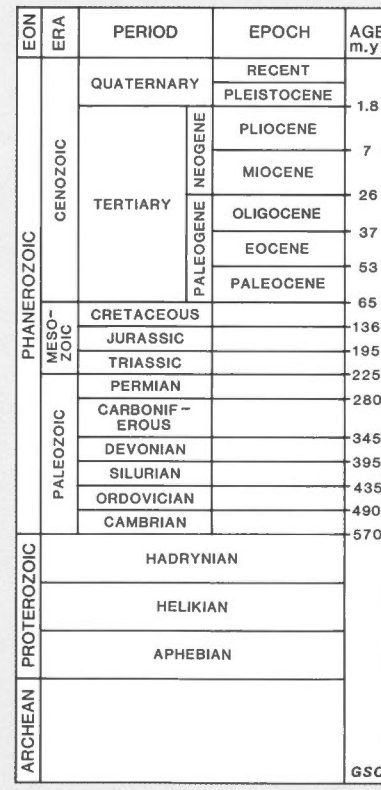


Figure 3.2 Geological time scale

WESTERN CANADA SEDIMENTARY BASIN

Introduction

The Western Canada Sedimentary Basin is a composite entity of two major westward-thickening, depositional wedges. The older wedge of late Proterozoic, Paleozoic, and early Mesozoic age was deposited on, and outboard of, the ancient North American craton in a passive margin tectonic setting. Both epeirogenic and eustatic events resulted in a number of cratonward converging unconformities, most apparent on the shallow platform, as well as controlled complex facies patterns of deposition of the various stratigraphic assemblages. The second wedge of late Mesozoic and Tertiary age records the change from a passive margin tectonic setting to one of active subduction. The collisions (often oblique), and episodic accretion of arc complexes and small composite terranes tectonically transported the outboard segments of the first wedge upwards and onto the older craton. The tectonic telescoping and thickening of this outer wedge depressed the crust, creating the migrating foredeep to receive the sediments of the clastic wedge eroded from the rising mountains.

Reserves

The remaining recoverable established reserves of oil and gas for the Western Canada Sedimentary Basin are listed in Table II. Oil reserves are concentrated in reservoirs of Devonian age (more than 60% of total) with Cretaceous strata containing about 25% of the total. In part this reflects the better recovery factor of lighter gravity oils from the reef fields (about 45%) compared to a broad range of light to heavy oils of the Cretaceous with an average recovery factor of less than 20%. Oil reserves listed do not include the heavy oils of the Lloydminster type that straddle the Alberta-Saskatchewan border (see Non-Conventional Resources, p. 48). However some heavy oil reserves located south of Lloydminster which are being produced conventionally, are included here.

Estimates of reserves prepared by different agencies commonly vary. This variation reflects different views on the extent and ultimate performance of individual reservoirs, as well as the extent to which proposed secondary and tertiary recovery process expectations have been incorporated. The values for oil reserves listed in Table II exclude enhanced oil reserves that are not fully demonstrated as to technical and economic performance.

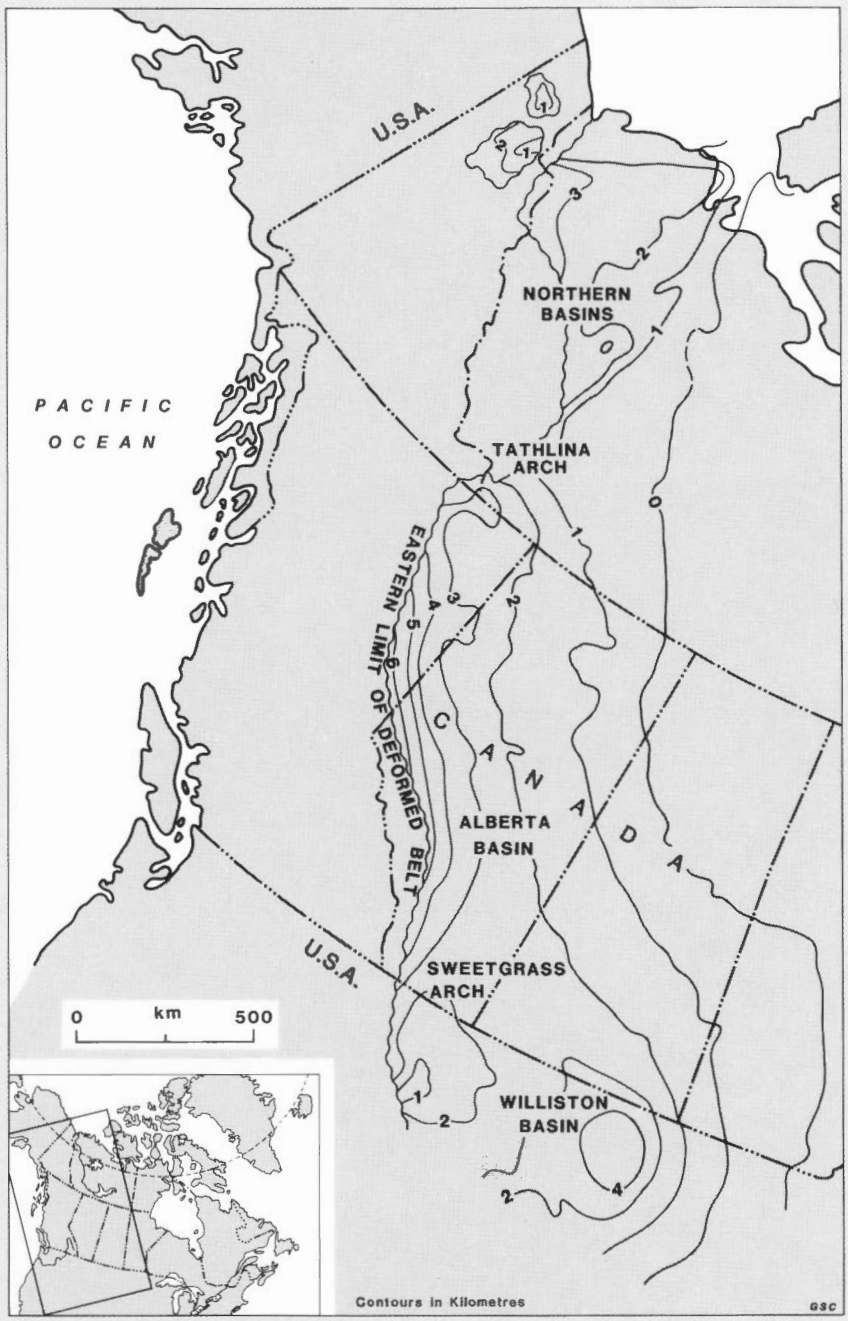


Figure 3.3 Basin fill map of Western Canada Sedimentary Basin. Contour interval in kilometres (after McCrossan and Porter 1973)

Almost half of the gas reserves occur in Cretaceous reservoirs, with Carboniferous and Devonian fields accounting for about 20% each. Sour gas with high hydrogen sulfide content is common in Paleozoic fields in Western Alberta, northeastern British Columbia and the Foothills Belt. More than 80 million tonnes of sulphur have been

produced and remaining reserves of sulphur exceed 120 million tonnes. About 10% of remaining reserves of gas occur at shallow depth in relatively poor quality reservoirs at low pressure. Reserves listed in Table II do not include gas trapped in very "tight" reservoirs of the "Deep Basin" of Western Alberta (see Non-Conventional Resources), Table II, however does include reserves that occur in conventional reservoirs within the same area, such as the giant Elmworth Field.

Ethane and Natural Gas Liquids (NGLs) have not been included in Table II but recent estimates indicate remaining gas reserves could also contain more than 300 million cubic metres of ethane and more than 320 million cubic metres of NGLs (propanes, butanes, and pentanes plus).

Potential

The oil and gas potential estimated to exist in the basins of Western Canada are listed in Table III. Although many of the exploration plays for this region are in a mature stage of exploration, several will continue to generate new discoveries. These will tend to be individual pools smaller than those already found and will require a greater level of exploratory effort. New plays and major extensions of existing plays are expected to add most to future discoveries. In spite of the control provided by drilling data, there are still large areas in which deep drilling is so sparse that traps of significant size could have been missed. This is particularily true in south-central Williston Basin, most of southern Alberta and much of west-central Alberta — British Columbia. Geological-geophysical models require refinement for exploration in the prospective Middle Devonian through Carboniferous sequences around the Peace River Arch, the Disturbed Belt in general, and southeastern British Columbia. The Devonian Deep Basin as well as Leduc and Nisku reef patterns on the plains are still not completely understood but will probably yield large to moderate discoveries from traps as yet unseen beneath carbonate shelves that mask the geophysical signals. Future discoveries may include many subtle traps that can best be located by careful reconstruction of the geological history, intensive seismic interpretation, modelling, hydrodynamic considerations and more closely spaced drilling.

Economic and Environmental Considerations

Activity in this area has been primarily in the Alberta Basin where exploration has yielded large discoveries of high quality light oil and heavy oil as well as large quantities of natural gas. Hydrocarbon bearing formations have been found at shallow (1000 metres) to medium (2500 metres) depth. Many of the formations in Northeast B.C. contain sour natural gas which requires additional treatment. The major constraint to future activity is the current lack of natural gas markets.

The Foothills area has higher cost drilling due to higher logistics costs, greater drilling depth, and hard rock formations. Natural gas in the Foothills area tends to be sour, requires special processing, and formations tend to require fracturing. Future activity will be restricted due to the lack of natural gas markets.

Activity in the Northern Basins has not been as intensive as in other areas of Western Canada, with exploration centered around Norman Wells. Some environmental hazards are encountered due to discontinuous permafrost resulting in higher costs.

Comparative drilling costs for parts of Western Canada in 1983 dollars per metre are:

Alberta Basin	$250-300
Williston	$250-300
Disturbed Belt	$550-700
Northern Basins	$250-300

TABLE II
ESTABLISHED REMAINING RESERVES

	OIL $10^6 m^3$	GAS $10^9 m^3$
Alberta Basin	600.3	1827.1
Williston Basin	108.4	47.6
Disturbed Belt	0.8	226.6
Northern Basins	44.2*	9.3*
TOTALS	753.7	2110.6

* These values represent fields that are not yet fully delineated, and should be considered as best current estimates of discovered resources rather than established reserves.

TABLE III
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL ($10^6 m^3$)	High Confidence	Average Expectation	Speculative Estimate
Alberta Basin	160	**398**	580
Williston Basin	32	**95**	292
Disturbed Belt	5	**15**	65
Northern Basins	14	**85**	415
TOTAL	*234	**593**	*1210

GAS POTENTIAL ($10^9 m^3$)	High Confidence	Average Expectation	Speculative Estimate
Alberta Basin	1120	**1817**	3764
Williston Basin	85	**107**	183
Disturbed Belt	255	**425**	1305
Northern Basins	42	**155**	820
TOTAL	*1544	**2504**	*4930

* These numbers do not add arithmetically but must be summed using statistical techniques

ALBERTA BASIN

Area 880 000 square kilometres, extending from the 49th parallel to the Tathlina Arch, and from the eastern limit of the disturbed belt eastward to the Precambrian Shield and southwestward to the Sweetgrass Arch.

Geology This Basin which thins from six kilometres near the disturbed belt to a zero edge at the Precambrian Shield consists of two westward thickening sedimentary wedges. The first of mainly Paleozoic rocks was sourced from the east and is dominated by marine carbonate rocks. The second consists mainly of non-marine clastic rocks, derived from the west and of Mesozoic-Cenozoic age.

Earliest Paleozoic rocks consist of Cambrian sandstones, shales, and siltstones, derived from the shield and spread westward over the relatively low relief craton. Ordovician and Silurian deposition consisted largely of shallow water marine carbonates reflecting the most extensive marine transgression of the Phanerozoic, which at its maximum extent in the Late Ordovician, covered most of the North American craton. By the beginning of Middle Devonian time the central Montana Uplift, the Western Alberta Arch, Peace River Arch and the Tathlina Arch were all positive features from which much of the lower Paleozoic rocks had been stripped. The presence of the arches controlled the facies distribution and thickness of sediments from Middle Devonian through Carboniferous time, as transgressive seas encroached from northwest to southeast instead of from the west as earlier. The arches shed sands into the transgressive Devonian deposits and collectively restricted sedimentation to form massive Middle Devonian (Eifelian) salt deposits. The northwest margin of the basin was controlled by a massive reef barrier (Keg River) limiting the southern encroachment of normal marine waters. In successively younger Devonian units there was a progressive southward shift of the barrier reefs and progressively smaller associated salt basins. Frasnian deposition transgressed the Western Alberta Arch and Famennian deposits finally transgressed the crest of the Peace River Arch, re-establishing the marine connection between the cratonic platform and the adjacent continental shelf.

Earliest Carboniferous sedimentation is recorded throughout the basin by a thin dark brown to black, highly organic shale (Exshaw), one of the most persistent markers in the sedimentary column. Overlying shales give way to widespread shallow-water marine carbonates through most of the Early Carboniferous which closed with a series of sandstones and siltstones marking reactivation of most cratonic arches. The Peace River Arch reversed itself in the Early Carboniferous and was moderately subsident; during Late Carboniferous and Permian time it was the site of local foundering where more than 0.6 kilometres of section are preserved in a series of grabens. Most of the basin was emergent at the close of the Permian. An early Triassic transgression resulted in a sequence of dark shales, overlain by phosphatic shales and a regressive sandstone (Halfway) of Middle Triassic age. The Late Triassic consists of shallow water evaporitic carbonates and anhydrites overlain by thick bioclastic limestones. Much of the Triassic was removed by pre-Jurassic erosion, and uppermost units are present only in northeastern British Columbia.

Lower and Middle Jurassic rocks are mainly marine shales, with minor sandstones which are transitional to Upper Jurassic non-marine sandstones and shales of the Kootenay and Nikinassin formations. This marks the beginning of the Mesozoic-Cenozoic sedimentary "wedge" that formed in response to orogenic activity to the west. Uplift supplied continental sediments that spread eastward across the basin at about the same time that marine seaways advancing from the north and south joined to form a narrow seaway extending from the Arctic to the Gulf of Mexico in the Middle Cretaceous. Renewed orogenic activity in Late Cretaceous and Paleocene resulted in extensive non marine clastic sediments that covered the entire basin.

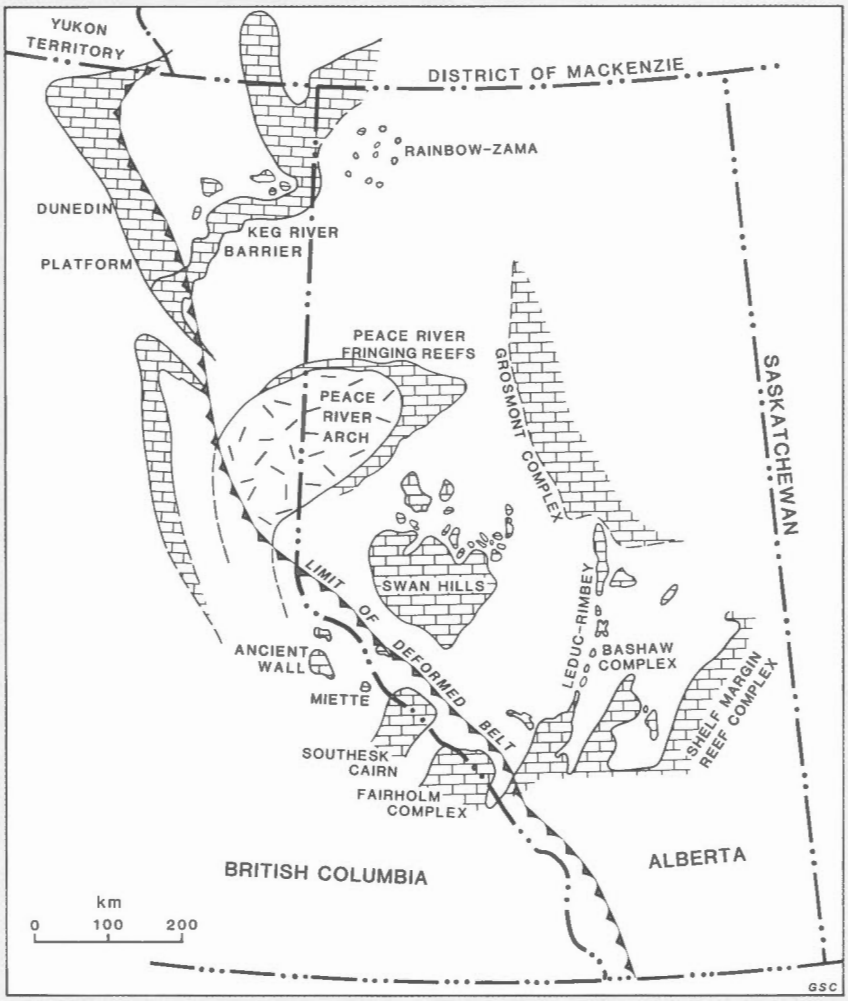


Figure 3.4 Map of major Devonian reef, bioherm, and biostrome complexes. Positions west of deformed belt palinspastically restored

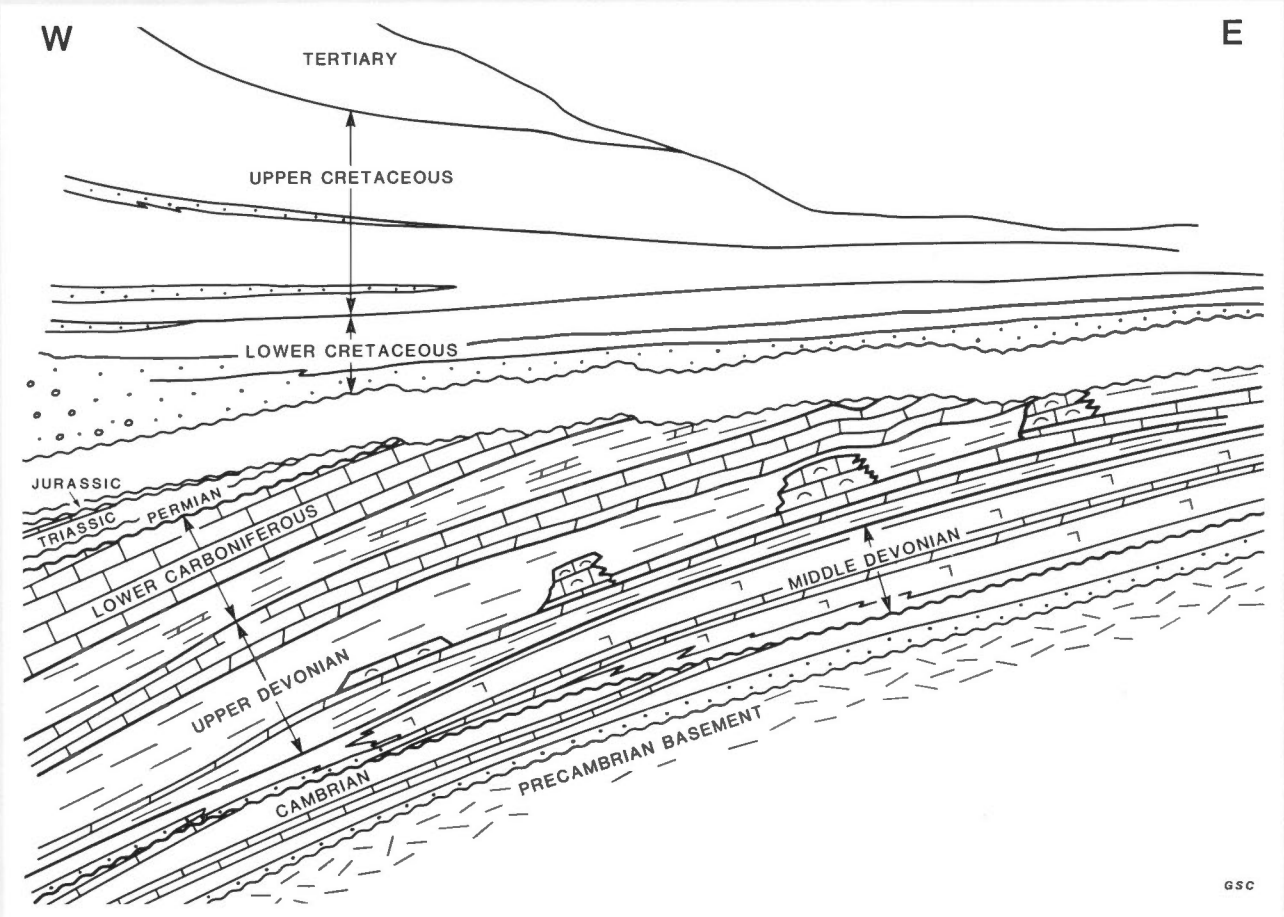


Figure 3.5 **Generalized stratigraphic section of Alberta Basin. Figure separated to emphasize the Foreland Basin**

Drilling History The first commercial gas field was discovered in 1904 at Medicine Hat in Upper Cretaceous rocks. Major exploration for oil followed the Devonian Leduc reef discovery in 1947. In total, more than 100,000 wells have been drilled in the basin.

Potential Source Rocks Potential source rocks are abundant throughout the section, particularily the dark shales of the Devonian, Carboniferous and Mesozoic. Thermal maturity ranges from immature in the shallow gas areas of the northern and eastern parts of the basin, to overmature in the deeper parts of the basin adjacent to the disturbed belt.

Potential Reservoir Rocks Good quality reservoir rocks are common throughout the section. Traditionally, the most important reservoirs have been the biogenic carbonates of the Devonian (bioherm and biostrome complexes of Figure 3.4); the subcrop edge of Devonian and Carboniferous units at the pre Jurassic unconformity; and the extensive basal and transgressive-regressive sandstones of the Cretaceous. Other prolific reservoir units include the Paleozoic transgressive sands surrounding the Peace River Arch and Triassic carbonates of northeastern British Columbia.

Known and Potential Hydrocarbon Occurrences More than 9,000 gas and 3,000 oil pools are identified within the Alberta Basin. Remaining established reserves are estimated to be 600 million cubic metres of oil and 1827 billion cubic metres of gas. Production to date has been approximately 1400 million cubic metres of oil and 1000 billion cubic metres of gas. For oil, about 65% of the reserves are in Devonian reservoirs and over 20% in the Cretaceous. For gas, about 50% of the reserves have been found in Cretaceous reservoirs and about 35% in the Devonian. Potential oil and gas occurrences are estimated to occur throughout the section but greatest opportunities will be in deeper (and older) rather than shallow horizons.

WILLISTON BASIN

Area Approximately 565 000 square kilometres (Canadian portion of Basin).

Geology The Williston Basin consists of relatively unstructured Paleozoic clastic and carbonate rocks largely derived from the Precambrian Shield that were beveled at the close of Paleozoic time, overlain by the westward derived Cretaceous-Tertiary clastic wedge. The basin was established by Middle Ordovician time when a series of cratonic arches rose to circumscribe the basin. Early sediments are clean Cambro-Ordovician sandstones derived from Cambrian sandstones from those arches as well as from Proterozoic sandstones from the Canadian Shield. Widespread thin, shallow-water shelf carbonates dominate the section from Late Ordovician to Late Silurian, extending from the Shield to central Montana. These rocks subsequently were deeply eroded in pre-Middle Devonian time due to strong uplift of surrounding arches, producing the prominent north facing Meadow Lake Escarpment (250 m high) which acted as a barrier in front of which thick salt deposits of Middle and Late Devonian age were deposited. Latest Devonian and Early Carboniferous successions consist of restricted euxinic shales overlain by open marine calcareous shales and limestones. The limestones that are crinoidal in the western part of the basin grade eastward to an evaporitic facies of dolomite and anhydrite. By the close of Carboniferous time, the evaporitic sequences extended to the centre of the basin. During Permian, Triassic and Early Jurassic time, the basin was isolated by uplift of its bordering cratonic arches and eroded at the margins. During this period the Sweetgrass Arch became prominent, effectively separating the normal shallow-water marine sedimentation of the Alberta Basin from the restricted red beds and minor salt deposits of the Williston Basin.

Since Late Jurassic the synorogenic clastic wedge spread eastward across all of the Western Canada Sedimentary Basin, initially with non-marine to marine shale and sandstone sequences; giving way to essentially non-marine clastic facies of the Paleocene to complete the depositional history of the basin.

Drilling History Although more than 20,000 wells have been drilled in the area, they have been concentrated in the producing areas. Much of the prospective area has yet to be tested by drilling.

Potential Source Rocks Winnipeg, Bakken, Exshaw, Jurassic and Cretaceous shales.

Potential Reservoir Rocks Potential reservoir rocks are common throughout the section including Cambro-Ordovician sandstones, Early Carboniferous carbonates of eastern and central parts of the basin, and Jurassic-Cretaceous sandstones.

Known and Potential Hydrocarbon Occurrences The most important oil accumulations are associated with the eroded Carboniferous subcrop belt of southeastern Saskatchewan and in southwestern Manitoba where more than 120 pools contain over 300 million cubic metres of recoverable oil. Major fields include Weyburn, Midale, and Steelman. The second most important group of fields produce gas and oil from Middle Jurassic Shaunavon and upper Jurassic-basal Cretaceous Roseray and Cantuar Formations, in a 200 kilometre long belt in southwestern Saskatchewan. These deposits are combined stratigraphic-structural traps associated with the western margin of the basin. Oil production is obtained also from Bakken sandstones. Extensive, shallow, low pressure gas reserves and potential occur along the western margin of the basin in Milk River - Medicine Hat sands. The most recent oil discoveries have been in southwest Manitoba where red beds of Triassic-Jurassic age overlie the Carboniferous subcrop (Waskada field).

Additional potential is anticipated in lower Paleozoic sandstones and dolomites, Devonian carbonates, as well as in the established reservoir units.

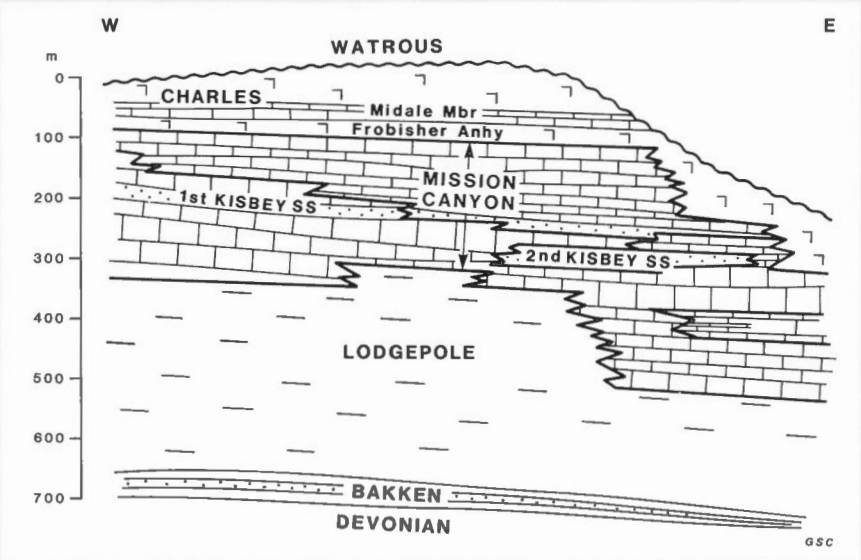


Figure 3.6 Detailed facies relationships of the Carboniferous stratigraphy of the Williston Basin that will result in stratigraphic traps (after Edie 1958)

DEFORMED BELT

Area 193 000 square kilometres, approximately 40 000 square kilometres in the Foothills in a linear belt extending 1000 kilometres northerly from the United States border at Waterton to the Southern District of Mackenzie.

Geology Like the adjacent plains, the stratigraphic record of the Deformed Belt consists of two westward thickening sedimentary wedges. The older, dominantly marine, Paleozoic and early Mesozoic wedge is the continuation of that of the adjacent plains. However, it contains the transition from platformal sediments of the plains to the equivalent, though much thicker successions of the miogeocline. Additionally much of the succession missing at unconformities in the plains is still preserved in the Deformed Belt permitting a fuller reconstruction of the paleogeography. The second major wedge of late Mesozoic and Cenozoic age constitutes the clastic wedge shed eastward into a migrating foredeep that formed in response to the loading imposed by the rising and telescoping of the mountains. Much of the earlier deposits of the clastic wedge were themselves cannibalized and redeposited into younger, eastern parts of the foredeep. Structurally, the Disturbed Belt consists of two major elements, the Rocky Mountains and the Rocky Mountain Foothills. Only the latter has seen significant exploration activity. Structures are typical of "thin-skinned" deformation, nevertheless, regionally a wide variety of styles are developed within that framework. Imbricate thrusts dominate the southern area (Figure 3.7) whereas blind thrusts and folds (Figure 3.8) are dominant in the northern areas.

Drilling History The first oil well drilled in Western Canada was drilled in 1902 at Oil City which is now within Waterton National Park. Since then numerous major oil and gas fields have been discovered from Waterton in the south to Beaver River in the northern part of the belt. The belt nevertheless has not been intensively drilled because exploration is expensive, seismic difficult, and most of the gas is sour, corrosive, and environmentally hazardous.

Potential Source Rocks Dark marine shales of Devonian and Mississippian age are the major source rocks in the south. A variety of similar Paleozoic and Mesozoic rocks occur in the north. Current maturation studies suggest the possibility of lesser levels of maturity in the western portions than has been conventionally accepted.

Potential Reservoir Rocks The main reservoir rocks occur in Mississippian and Cretaceous sequences in the south whereas major Devonian and Triassic reservoirs occur as well in the northern Foothills. Porosity is commonly reduced because of deeper burial, however, fractured reservoirs are common.

Known and Potential Hydrocarbon Occurrences The remaining established reserves are 226.6 billion cubic metres of gas and 0.8 million cubic metres of oil. Because much of the gas is sour and must be processed, sulphur has become a significant commercial byproduct. Compared with the other parts of the Western Canada Sedimentary Basin, the Disturbed Belt has a very low drilling density, many plays remain untested.

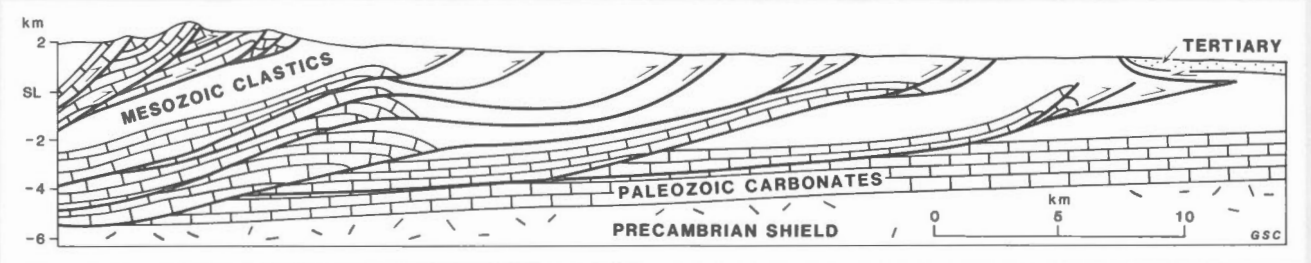


Figure 3.7 Generalized structure section of southern Alberta Foothills. Thrusting dominates folding (after Bally *et al* 1966)

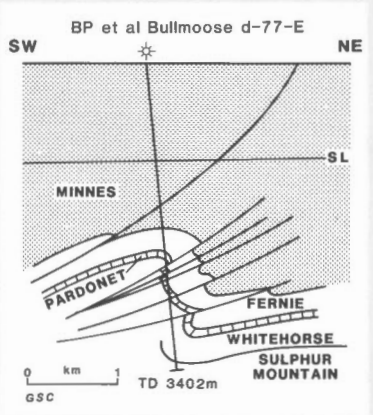


Figure 3.9 Structure section, Bullmoose Field, Northeastern British Columbia (after Barss and Montandon 1981)

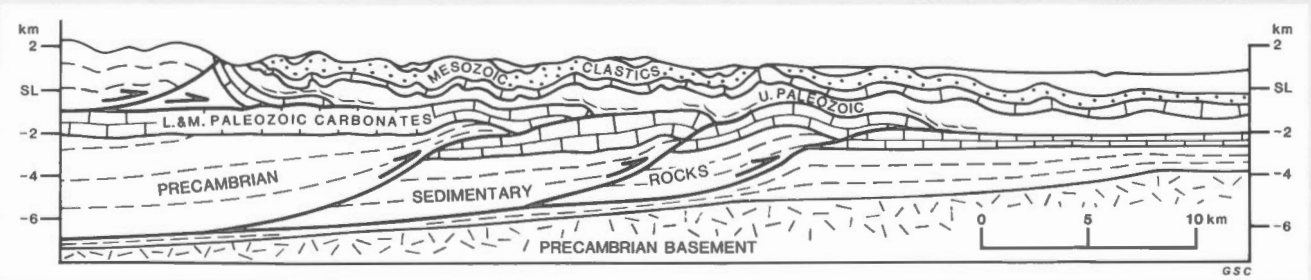


Figure 3.8 Generalized structure section of northern British Columbia Foothills. Blind thrusts and folds dominate

NORTHERN BASINS

Area Approximately 490 000 square kilometres. About 30 000 square kilometres of this total lies west of the Richardson Mountains in the Eagle Plain and Old Crow Basins.

Geology The northern extension of the Western Canada Sedimentary Basin is usually discussed as a series of separate basins or physiographic regions (Figure 3.10). These include the Anderson Plain, Mackenzie Plain, Peel Plain and Peel Plateau, plus the Eagle Plain and Old Crow Basins to the west of the Richardson Mountains. However, in simple terms, the whole area is somewhat analogous to the Alberta basin, in that the total section consists of two major wedges of sedimentary rocks separated by a major unconformity surface.

The lower wedge consists of platformal rocks, dominantly marine carbonates, which persist from Early Cambrian through Middle Devonian. This carbonate and shale sequence, which is broken by several regional unconformities, was derived from the Precambrian Shield and thickens to about 3000 metres at the outboard margin of the craton. Lower Cambrian deposits are widespread in the Peel Plateau area. In deeper parts of the region (Figure 3.11), the carbonate sequences pass laterally into black graptolitic shales. Middle Devonian reefs (Figure 3.12) were developed in the Mackenzie Plain area and in the Eagle Plain Basin. Upper Devonian rocks of the Eagle Plain Basin include clastics shed from uplifts to the north with deposition continuing into the Late Paleozoic time. Elsewhere, Late Paleozoic rocks are largely missing or were not deposited since most of the area was above sea level. Late Jurassic marine shales mark the beginning of a major transgression, and thick lower Cretaceous basal sandstones and shales are present over much of the area. Upper Cretaceous and Tertiary rocks, that were derived mainly from Laramide uplift to the west and south were mainly removed as the Mackenzie River drainage system developed.

Drilling History The earliest drilling resulted in the discovery of the Norman Wells oil field in 1920. Since then about 150 wells have been drilled in the area, most of them since 1960. There are 24 wells drilled in Eagle Plain Basin but none in the Old Crow Basin.

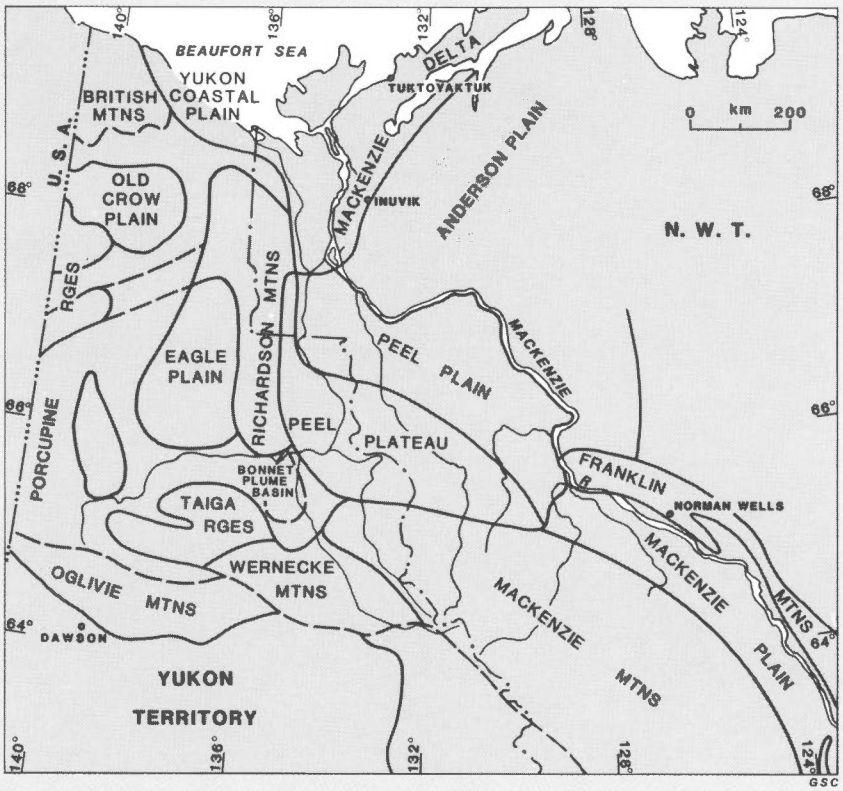


Figure 3.10 Physiographic subdivisions of the Northern Basins (after Kunst 1973)

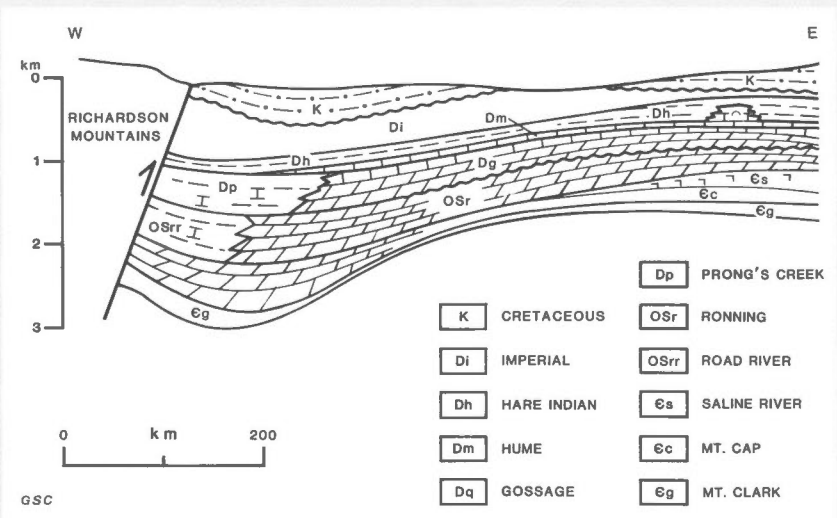


Figure 3.11 Schematic stratigraphic section across Peel Plateau (after Kunst 1973)

Potential Source Rocks Potential source rocks exist in shales of both Paleozoic and Cretaceous age, including the Ordovician to Devonian graptolitic shales and bituminous shales of the Middle and Upper Devonian. Proterozoic shales also may provide hydrocarbons in the Peel Plateau area.

Potential Reservoir Rocks The most prospective reservoir rocks have been the biohermal facies of Middle Devonian age. Several sandstones of Cambrian, Carboniferous, Permian and Cretaceous age are also potential reservoir rocks.

Known Hydrocarbon Occurrences The Norman Wells oil field is the largest discovery in the region and is estimated to contain about 40 million cubic metres of recoverable oil. There have been three gas, and one gas and oil discoveries in Carboniferous sandstones in the Eagle Plains Basin. At Tedji Lake, a gas discovery in Cambrian sandstones is estimated to contain about 2.5 billion cubic metres.

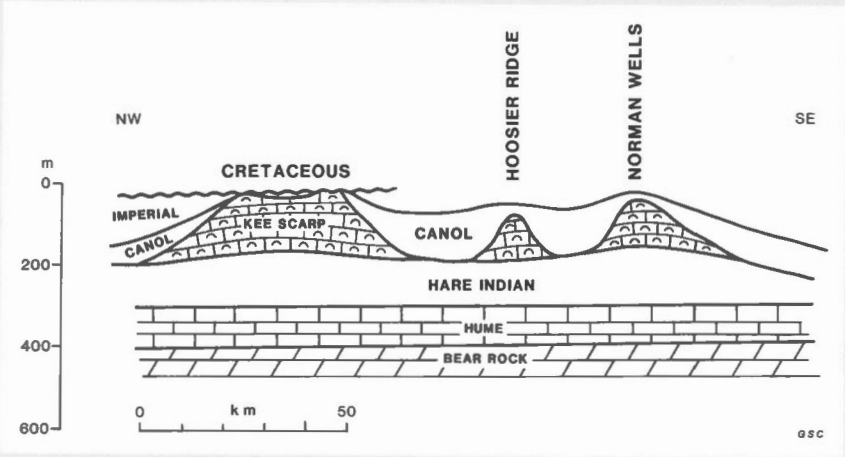


Figure 3.12 Stratigraphic relationships of the Devonian Kee Scarp reefs

CORDILLERAN BASINS

Introduction

Recent concepts envisage the Cordillera as the product of continental collision between North America and at least two other terranes. Docking of these exotic terranes during Jurassic and Cretaceous time produced the sutured tectonic welts of metamorphic and plutonic rocks that subdivide the Cordillera and produced the tectonic telescoping and thickening of the Rocky Mountain deformed belt. Thus the later Mesozoic and Tertiary successor basins of the Intermontane region are underlain by varied sequences that originated outside of the North American paleogeographic context.

Unlike the other coastal regions of Canada, the West Coast is a tectonically active plate margin where subduction and large scale translation of the earth's crust has, and is taking place. The British Columbia Offshore region is located in the Insular Tectonic Belt which like most of British Columbia is composed of allocthonous terranes that have been accreted to the western margin of the ancestral North American Plate. Prospective areas for petroleum occur in sedimentary sequences that were deposited as portions of the exotic terranes prior to accretion; in melange and foredeep assemblages in response to collision and suturing; and in postsuturing basins in response to continued subduction.

Reserves and Potential

No reserves have been discovered in this region, and estimates of potential have not yet been prepared for the Intermontane Basins. Based on limited available geochemical evidence, the Intermontane Basins are considered unlikely to contain significant oil potential. The thermal metamorphism associated with these basins suggests that relatively small quantities of dry gas potential may exist, although other authors have estimated that about 150 billion cubic metres of gas potential might be appropriate.

For the westcoast offshore basins, estimates of potential are listed in Table IV. The more prospective areas for petroleum are located primarily on the Wrangellia Terrane with local overlap onto portions of the Alexander Terrane to the north, and the Olympic and Pacific Rim Terranes to the south. Two large sedimentary basins are known — the Queen Charlotte Basin lying between the Queen Charlotte Islands and the Mainland, and the Tofino Basin lying off the west coast of Vancouver Island. There is also the small Winona Basin on the continental slope off northern Vancouver Island, and the larger though shallow Nanaimo Basin lying between Southern Vancouver Island and the Mainland. The Tertiary sections of both Queen Charlotte and Tofino basins have been tested by a number of wells but with no success. Due to environmental constraints there has been no drilling in the offshore since 1969. Many of the play concepts, particularly those conceived to be beneath the Tertiary sedimentary cover, have yet to be tested by drilling, therefore the estimates presented here reflect a high degree of uncertainty common to many frontier areas.

TABLE IV
OIL AND GAS POTENTIAL
WEST COAST OFFSHORE

	High Confidence	Average Expectation	Speculative Estimate
OIL POTENTIAL ($10^6 m^3$)		50	110
GAS POTENTIAL ($10^9 m^3$)	40	270	760

QUEEN CHARLOTTE BASIN

Area The region comprises approximately 50 000 square kilometres, and includes the areas underlying Queen Charlotte Sound, Hectate Straits and Dixon entrance on the continental shelf out to a depth of water bounded by the 200 metre isobath.

Geology Above an economic basement of Triassic age Karmutsen volcanics is a thick, mainly marine sequence of volcanoclastic sands, shales, limestones and siltstones of Jurassic age. Faulted, folded and locally eroded, they are overlain by clastics of both Lower and Upper Cretaceous age. Both sequences were again subjected to faulting and folding in Late Cretaceous time. Thick volcanics of the Masset Formation unconformably overlie the succession in the northwest and interfinger laterally with the lower part of the thick Tertiary clastics. A major depocentre of the post-suture sediments of the Miocene Skonun Formation overlies a rift in southern Queen Charlotte Sound where sediment thicknesses of 4500 metres are reported.

Drilling History In 1915, British Columbia Coal Company drilled a shallow (490 m) well on Graham Island. Royalite drilled the onshore Queen Charlotte well (1006 m) in 1950. Richfield drilled six onshore shallow (all less than 2500 m) wells on Graham Island during 1958-1961. Between 1967 and 1969, Shell Canada drilled fourteen offshore wells testing Tertiary plays, eight of which were located in Queen Charlotte region.

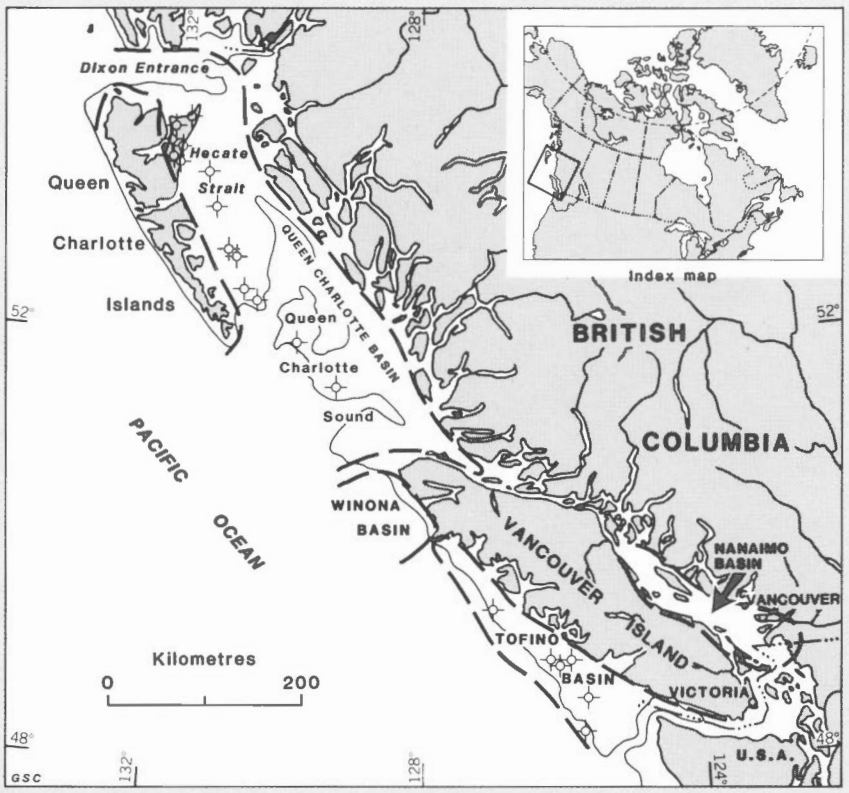


Figure 3.13 Location map of west coast British Columbia basins

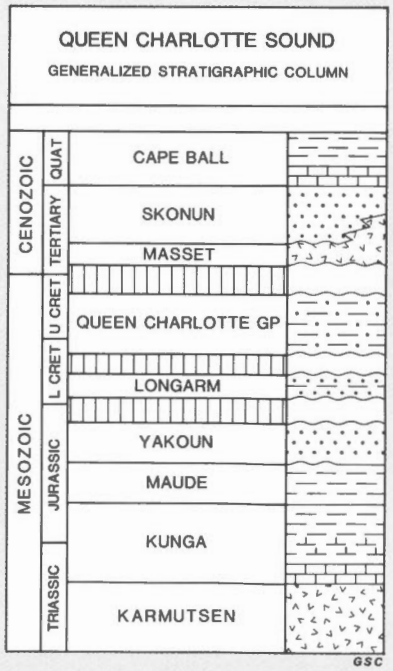


Figure 3.15 Queen Charlotte Sound

Potential Source Rocks Organic rich shales of the Jurassic Kunga and Maude Formations are known to have generated oil, some of which has migrated from the source beds. Carbonaceous marine shales are known to occur in the Cretaceous Queen Charlotte Group. Within the Tertiary sequences lignites occur in the Skonun Formation. however, most of the Tertiary section is considered to be thermally immature.

Potential Reservoir Rocks Sandstones are common in much of the pre-Cretaceous allocthonous and suture assemblages, however many are volcanoclastic in origin with consequent restricted porosities and permeabilities. The Cretaceous sequence contains several good clean marine sandstones. Tertiary sandstones have good measured porosities but the feldspar rich sandstones have variable to poor permeabilities.

Known Hydrocarbon Occurrences Oil staining was reported from the offshore Sockeye B-10 well. Gas was flared from an early (1915) onshore well in the Queen Charlotte Islands. Tar filled vesicles occur in the Masset volcanics and also in the Middle Jurassic Yakoun Formation.

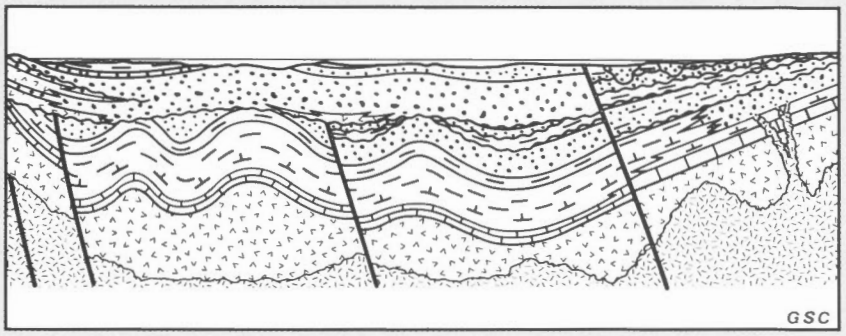


Figure 3.14 Schematic stratigraphic section across Queen Charlotte Sound

TOFINO AND WINONA BASINS

Area The Tofino Basin underlies an area of the continental shelf and slope off Vancouver Island of approximately 9000 square kilometres inboard of the 200 metre isobath (Figure 3.11). The Winona Basin underlies an area of the continental shelf and slope off northern Vancouver Island of approximately 5000 square kilometres most of which lies outboard of the 200 metre isobath.

Geology Thick (4000 metres) sections of low velocity sediments have been identified by seismic profiling in both the Tofino and Winona Basins. Drilling in the Tofino Basin has confirmed the Late Tertiary age of these sediments. The sediments unconformably overlie Early Tertiary and Mesozoic deformed volcanic, plutonic, and sedimentary rocks. The Neogene sediments form a relatively undeformed wedge which thickens seaward from Vancouver Island to the base of the continental slope. The sediments include mainly marine, poorly consolidated, calcareous mudstones and minor siltstones of Miocene to Pliocene age. Sandstones occur near the base of the succession. Large low amplitude structures occur, that are products of both subduction related tectonics and, or as a gravity induced response to overpressuring and diapiric movement of the shales.

The thick sediments of the Winona Basin have not yet been penetrated by drilling, as the major portion of the basin occurs beneath very deep water. Mudstone, sandstone conglomerate and minor coal have been dredged from canyon walls of the continental slope above the main portion of the Basin. The sediments form a wedge dipping seaward under the continental shelf and slope, outboard of which, they are downfaulted into very deep water. Deformation in the deep water segment of the basin is seen on seismic near the base of the slope and beneath Winona ridge located in deep water 110 kilometres offshore (See Figure 3.18)

Drilling History Shell Canada drilled six offshore wells testing the Tertiary sediments of Tofino Basin in the period 1967 to 1969. Recently there has been a moritorium on drilling in the waters offshore of British Columbia because of environmental considerations.

Potential Source Rocks Good source rocks have yet to be identified in the Neogene succession. All the fine clastics are light grey colored, organic poor mudstones.

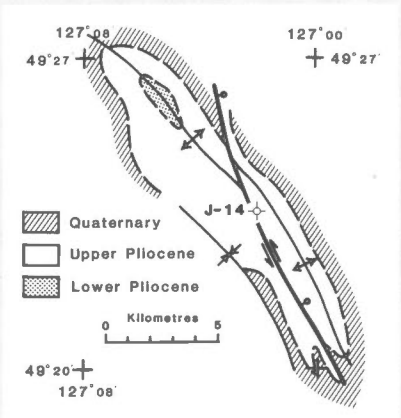


Figure 3.17 Exposed sea-floor structure, Apollo anticline (after Yorath 1980)

Potential Reservoir Rocks Good porosity and permeabilities have been measured in the sidewall cores from the exploratory wells. The better reservoir sandstones occur near the bottom of the succession.

Known Hydrocarbon Occurrences Minor gas shows were encountered in shallow zones in the Pluto I-87 and Prometheus H-68 wells in the Tofino Basin. Gas logging obtained relatively high methane values and C_2 through C_5+ values generally increased in the deeper and older Tertiary sediments.

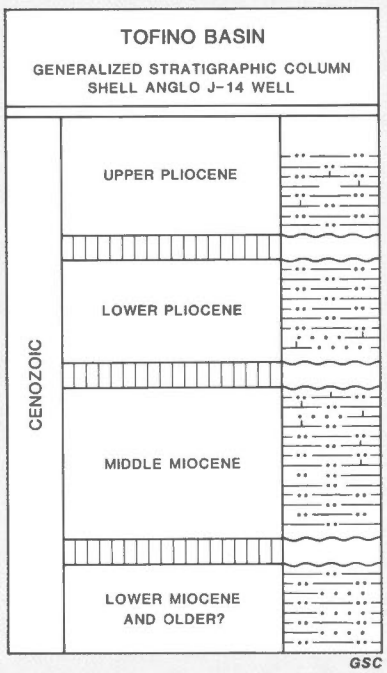


Figure 3.16 Tofino Basin

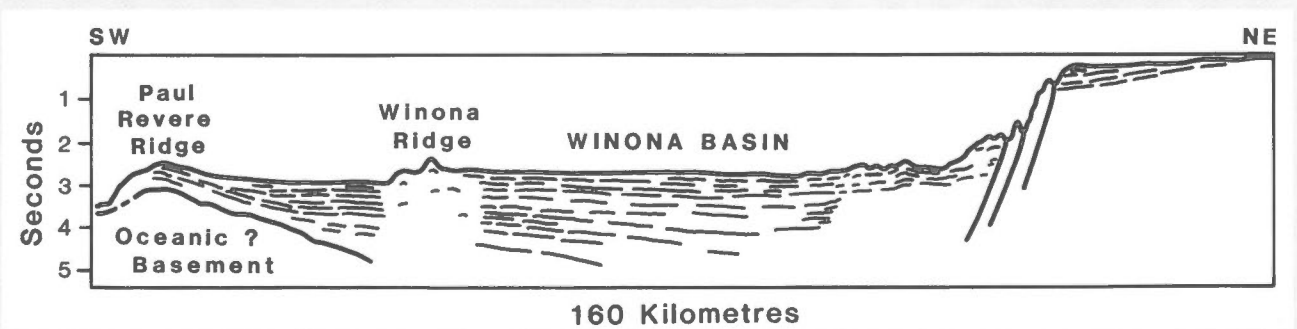


Figure 3.18 Schematic structure section (seismic) Winona Basin (after Chase *et al* 1975)

INTERMONTANE BASINS

Area 240 000 square kilometres; distributed among four major basins (Figure 3.19), the Whitehorse, Bowser, and Nechako Basins (including the Tyaughton Trough) and the Quesnel Trough.

Geology Lower Paleozoic carbonates and equivalent deep water siliceous shales overlie altered volcanic assemblages in most of the Intermontane Basins and contain exotic faunas relative to North America. Commonly overlain by Triassic carbonates and arc-type volcanics which also have been interpreted as exotic, they are, in turn, overlain by Jurassic synorogenic clastics believed to be the product of the accretionary collision. Another generation of coarse clastics of middle to Late Cretaceous age is the result of a second major accretion of terranes to the western margin of North America. The basins were strongly folded and faulted during each accretionary event. Total thickness of the sediments may have exceeded 12 000 metres prior to structural elevation and erosion in some of the basins. Late Tertiary to Recent volcanism has capped the Nechako Basin (Figure 3.20) obscuring the underlying geology.

Drilling History One well has been drilled in the Bowser Basin and four wells drilled in the Nechako Basin. Other basins are untested.

Potential Source Rocks Most of the basins contain coals or carbonaceous sandstones and the sediments are thought to contain mainly terrestrially derived organic material. All demonstrated very high levels of thermal maturity so that only overmature gases should be expected.

Potential Reservoir Rocks Sandstones are widespread within the various depositional sequences. Most were deposited as immature sediments whose porosity and permeability have been reduced by later alteration.

Known Hydrocarbon Occurrences A minor show of dry gas was recorded in the Bowser Basin well.

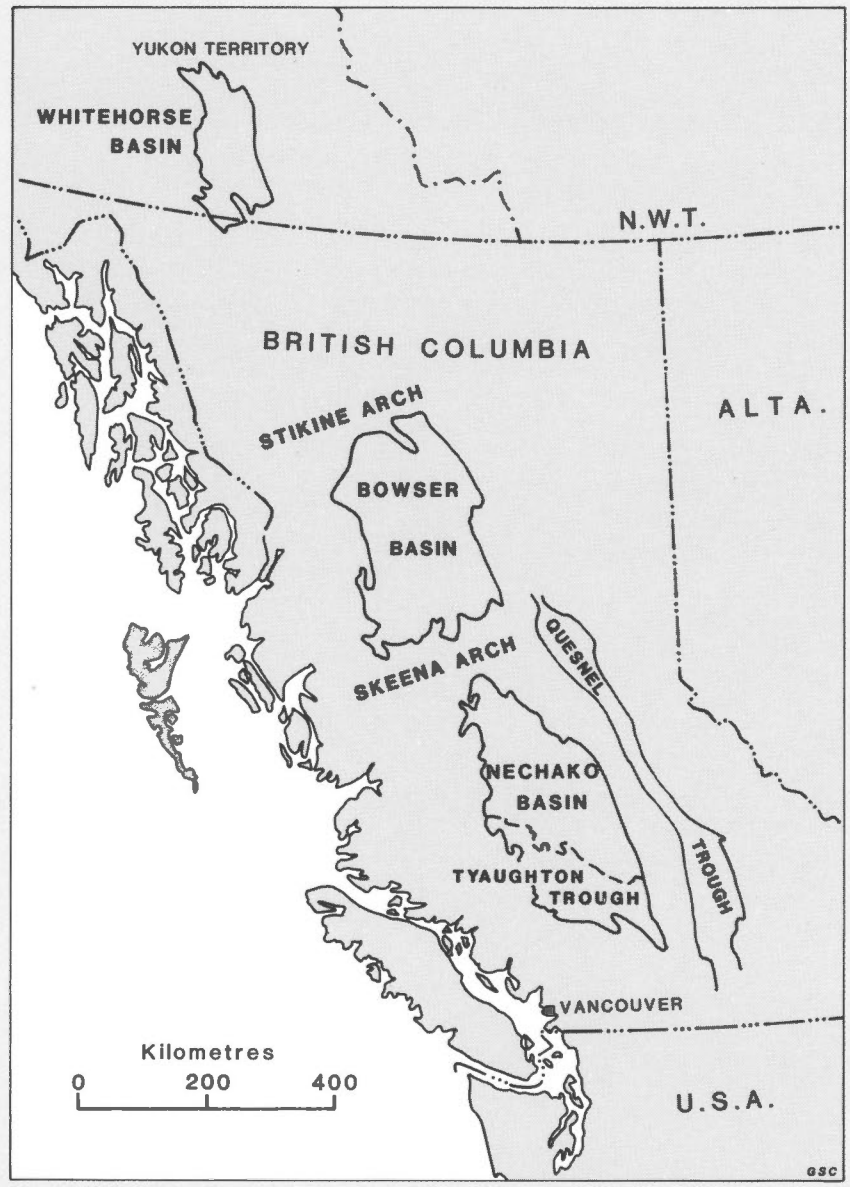


Figure 3.19 Location map of Intermontane Basins (after Koch 1973)

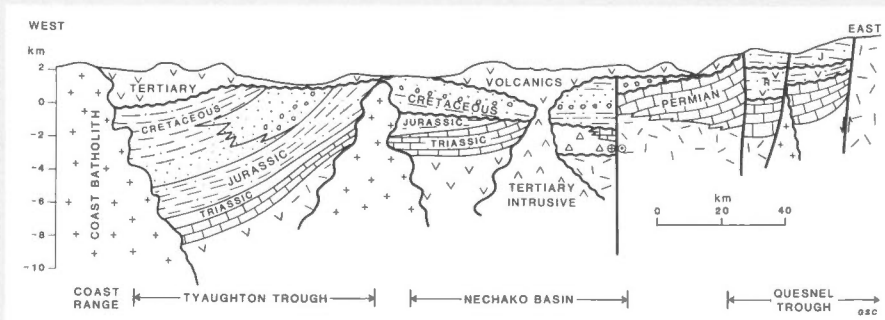


Figure 3.20 Schematic section from Tyaughton Trough to Quesnel Trough (after Koch 1973)

BEAUFORT SEA-MACKENZIE DELTA

Introduction

This region includes the onshore Mackenzie Delta, Tuk Peninsula and that part of the offshore extending to the edge of the continental shelf at a water depth of approximately 200 metres. This region is arbitrarily terminated to the northeast in the middle of Amundsen Gulf. The region is underlain by deltaic sandstones and shales of Mesozoic and Cenozoic age which thicken rapidly to more than 12 000 metres a short distance seaward from the present delta. These beds overlie faulted Paleozoic rocks stepping down steeply beneath the Mesozoic-Cenozoic cover. The Paleozoic rocks rise to the surface and are exposed in the southern part of the area. The basin contains a series of Mesozoic-Cenozoic depocentres. The thick Upper Cretaceous to Holocene clastics were deposited in a series of migrating deltaic wedges which built out over the passive type continental margin of the southern Beaufort Sea.

Reserves

Quantities of oil and gas discovered to date are listed in Table V. The values given are described as "best current estimates" of "discovered resources" rather than the more conventional terminology of "remaining established reserves" because for most of the discoveries, the nature and total extent of the reservoirs is poorly defined. In addition to a general lack of delineation drilling, there are many reasons for the wide spectrum of "reserve" estimates that exist for

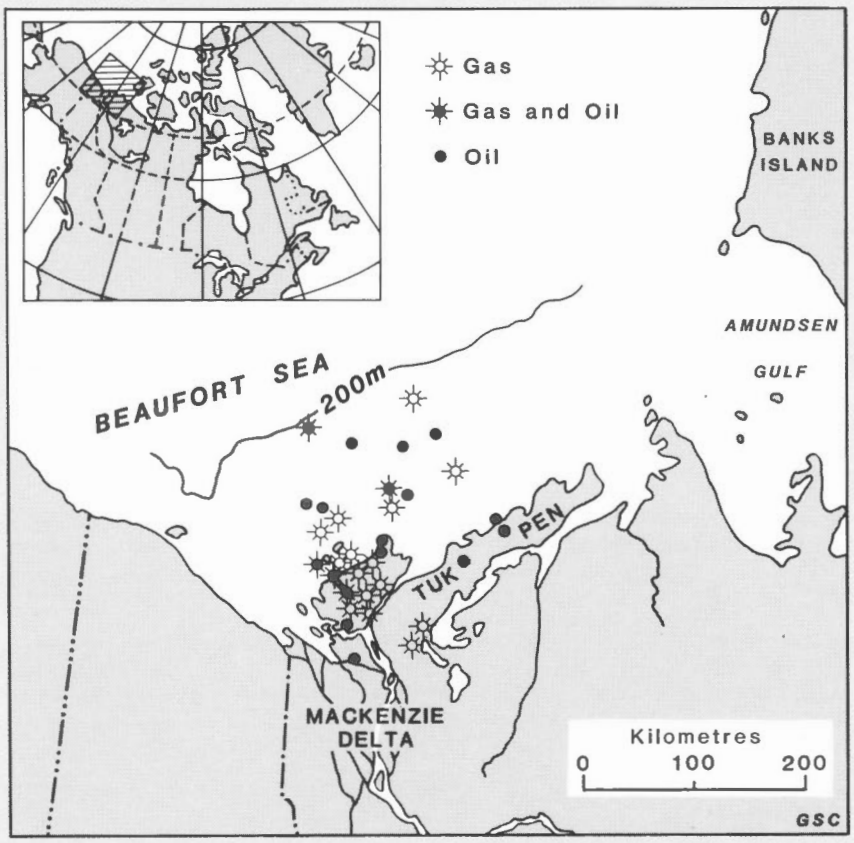


Figure 3.22 Oil and gas discoveries, Beaufort Sea-Mackenzie Delta

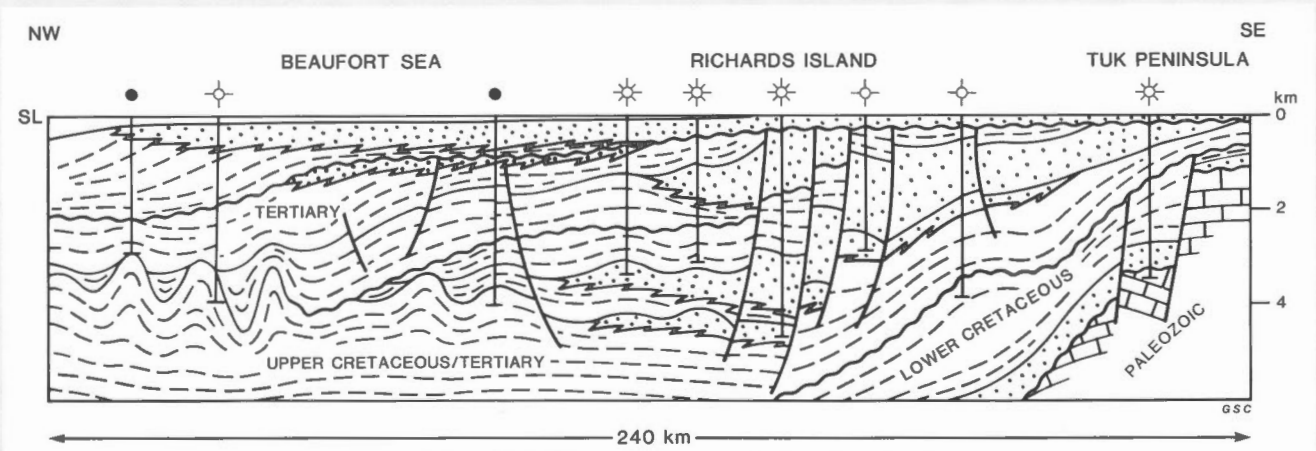


Figure 3.21 Schematic stratigraphic relationships, Beaufort Sea-Mackenzie Delta

this region, particularily those for the discoveries in the Beaufort sea. Unlike other frontier regions, many of the reservoirs here are usually poorly characterized by mechanical logs, are of poor to fair quality with questionable lateral continuity, do not have definitive drillstem testing and are not easily defined by seismic. The values expressed in Table V are an attempt to quantify what can be considered to exist with some reasonable confidence, amplified by geological-geophysical judgement as to lateral and vertical continuity. As such, they are conservative, and certainly subject to significant change.

Potential

The Beaufort Sea-Mackenzie Delta region is estimated to contain 1464 million cubic metres of oil and 2125 billion cubic metres of gas (average expectation) as shown in Table VI. Speculative estimates are almost 3000 million cubic metres of oil and over 4000 billion cubic metres of gas. These are high estimates for a relatively small region but not inconsistent with the high success rate and the early discovery of three near giant gas fields (85 billion cubic metres). The largest potential for both oil and gas is estimated to exist in the Beaufort Sea area, both in the part now being evaluated by drilling, and in the large part of the area westward to the Canada-United States boundary. The latter area is virtually untested but is known from seismic exploration to contain similar features to those of the main delta area. Within the area which has been the main focus of activity in recent years, there are many structures that have only been tested on the crest. Flank pinch-out plays, traps against faults and many others still require evaluation, as do the numerous stratigraphic plays associated with deltaic sedimentation.

Economic and Environmental Considerations

For purposes of economic evaluation, the Beaufort Sea area can be subdivided primarily in relation to water depth. The shallow areas, in depths less than approximately 20 metres, allow the construction of artificial islands. In greater water depths, platforms are required. In either offshore case, development systems will have to be able to withstand ice pressures, and transportation lines will have to be buried, or protected in some other manner, from ice to allow year-round operations. Although work has been done in the design of systems to permit year-round production and transportation from the Beaufort Sea, the technology is largely still untried.

Onshore, in the South Delta-Tuk Peninsula, development costs are potentially less than in the Beaufort Sea, although still substantially higher than those in the Western Provinces. Here, as in the Beaufort Sea, low temperatures combined with the long period of darkness leads to lower working efficiencies. The primary constraint to future development in the South Delta-Tuk Peninsula will be lack of natural gas markets at prevailing and forecast prices both in Canada and internationally. Transportation of oil from onshore and near-onshore reserves will depend on the commercial viability of a transportation system which may require supplemental quantities of oil from the Beaufort Sea. Drilling costs in the onshore delta have ranged between $2-$3 thousand per metre (1983 dollars). This is approximately twice the cost for drilling farther south in the Mackenzie corridor and is approximately 4-6 times greater than for drilling in Western Canada. In the Beaufort Sea, drilling costs of exploration have ranged between $10-$13 thousand per metre (1983 dollars) where artificial islands are used as drilling bases, and $25-$30 000 per metre where drillships are used. Market prices for petroleum from the Beaufort Sea-Mackenzie Delta area must be sufficient not only to cover transportation costs but also much higher development costs. Development costs for an oil field such as Tarsiut, located in 22 metres of water, are expected to be in the range of $4-$6 billion (1983 $).

The main environmental concern in the region focuses on the potential impact of oil spills. The extent of damage depends on factors which include the volume of oil spilled, ice conditions, prevailing oceanographic and meteorological conditions, time of year, and success of oil spill countermeasures. Tanker transportation modes potentially pose a greater environmental hazard than pipelines.

TABLE V
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL $10^6 m^3$	GAS $10^9 m^3$
Issungnak	15.9	70.8
Niglintgak	3.7	22.7
Parsons	3.6	62.3
Taglu	7.2	68.0
Tarsiut	23.8	2.4
Other discoveries (listed by name only)	63.0	60.2
TOTAL	117.2	286.4

Other Discoveries

Adgo	Kugpik
Atkinson	Kumak
Garry North	Mallik
Garry South	Mayogiak
Imnak	Nektoralik
Isserk	Nerlerk
Itiyok	Netserk
Ivik N.E.	Pelly
Ivik S.W.	Reindeer
Kamik	West Atkinson
Kenalooak	Titalik
Kiggavik	Ukalerk
Koakoak	Ya Ya North
Kopanoar	Ya Ya South

TABLE VI
OIL AND GAS POTENTIAL

OIL POTENTIAL ($10^6 m^3$)	High Confidence	Average Expectation	Speculative Estimate
South Delta-Tuk Peninsula	8	88	171
Richards Island-Beaufort Sea	287	1376	3060
TOTAL	*307	1464	*2962

GAS POTENTIAL ($10^9 m^3$)	High Confidence	Average Expectation	Speculative Estimate
South Delta-Tuk Peninsula	93	209	402
Richards Island-Beaufort sea	747	1942	4070
TOTAL	*871	2151	*4103

NB Estimates for this region are under review at time of printing
* These numbers do not add arithmetically but must be summed using statistical techniques

SOUTH DELTA-TUK PENINSULA

Area 30 000 square kilometres; includes offshore extension of Tuk fault zone to 71°N.

Geology Proterozoic, Devonian, and Permian clastics, volcanics, and carbonates have been identified in subcrop under the Mesozoic-Cenozoic cover of the South Delta-Tuk Peninsula. Presumably a Cambrian to Silurian succession also underlies the area. Where penetrated the Proterozoic rocks consist of clastics and volcanics; those of the Cambrian to Devonian are carbonates; and the Permian succession consists of clastics. Nine basin-wide Jurassic and Early Cretaceous depositional sequences are recognized. Each generally consists of a thick prograding lens of sandstone and shale of dominantly marine facies. Thickness variations were controlled by a system of basement arches and troughs that were active at the time of deposition. Paleoshorelines mimic the present northeast-southwest orientation although occurring farther southeast onto the craton. Maximum transgression occurred during Albian time. The Jurassic-Lower Cretaceous rocks are unconformably overlain by Upper Cretaceous shales, which are overlain by a thin succession of Tertiary sands.

Drilling History The first exploratory well was drilled in the area in 1969 (Tuk F-18) and oil was first discovered at Atkinson Point in 1970. To date 74 wells have been drilled in the South Delta-Tuk Peninsula region.

Potential Source Rocks The Upper Cretaceous Boundary Creek Formation has been identified as the source rock for the oil at several discoveries. The condensates and gas in the Parsons field are believed to be sourced from shales of the Husky Formation and although it contains abundant terrigenous organic material, its source potential is not yet fully understood. Similarly organic rich shales occur in the Albian Arctic Red Formation.

Potential Reservoir Rocks The interdigitation of shales and sandstones throughout the sequences provide ample opportunity for both reservoir and seal occurrences.

Known Hydrocarbon Occurrences Oil has been discovered at Kugpik, Kumak, Atkinson, West Atkinson, Imnak, and Mayogiak (the Mayogiak and West Atkinson oils are trapped in Devonian carbonates). Major accumulations of natural gas and condensate have been discovered at Parsons Lake where recoverable reserves have been estimated at 62.3 billion cubic metres gas and 3.6 million cubic metres of condensate.

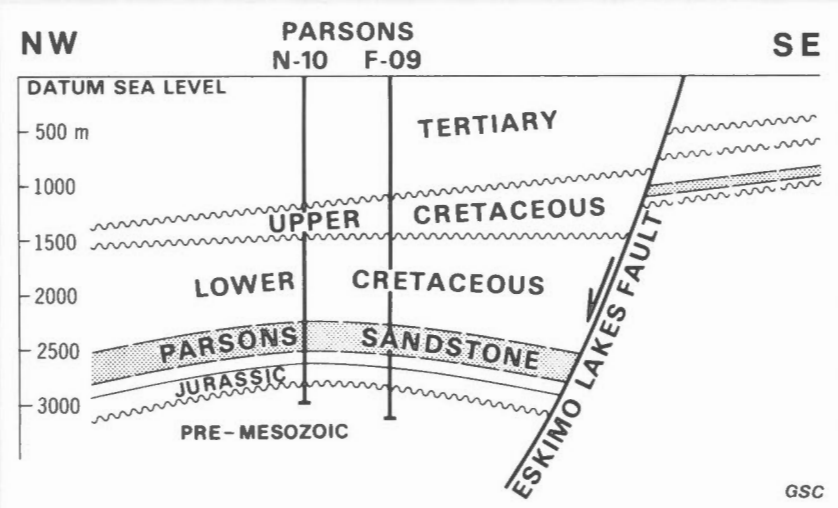


Figure 3.23 Schematic structure section, Parsons Lake Gas Field (after Cote *et al* 1973)

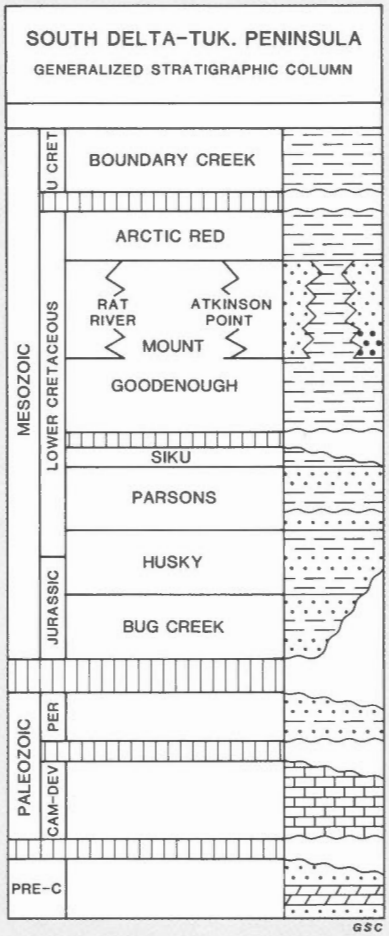


Figure 3.24 Mackenzie Delta-Tuk Peninsula

RICHARDS ISLAND — BEAUFORT SEA

Area Approximately 55 000 square kilometres extends seaward to the 200 metre isobath.

Geology The basin contains a series of late Mesozoic-Cenozoic depocentres, in which clastic sediments were deposited in a series of migrating deltaic wedges and associated turbidity flow deposits. Rapid basin subsidence and undercompaction of sediments resulted in large scale syndepositional listric faulting and mud diapirism. Nine major depositional sequences deposited in response to eustatic changes in sea level are identified. Each have complex facies distributions reflecting the varied position in time and space of shelf to slope breaks and channel positions of the major sediment influx. In general, each sequence progrades farther basin-ward than its predecessor resulting in downlapping and offlapping relationships.

Drilling History The first exploratory well drilled in the area was on Richards Island in 1966 (Reindeer D-27). Drilling activity moved offshore, with the use of artificial islands beginning in 1973 and ice-strengthened drillships in 1976. To date a total of 82 wells have been drilled in the Richards Island-Beaufort Sea area.

Potential Source Rocks The actual source rocks have yet to be identified. Studies suggest that significant vertical migration has occurred and the peculiar nature of the recovered crudes suggests they were generated from resin-enriched terrestrial organic material at lower than normal levels of thermal maturity.

Potential Reservoir Rocks Reservoir quality sandstones are present throughout the basin.

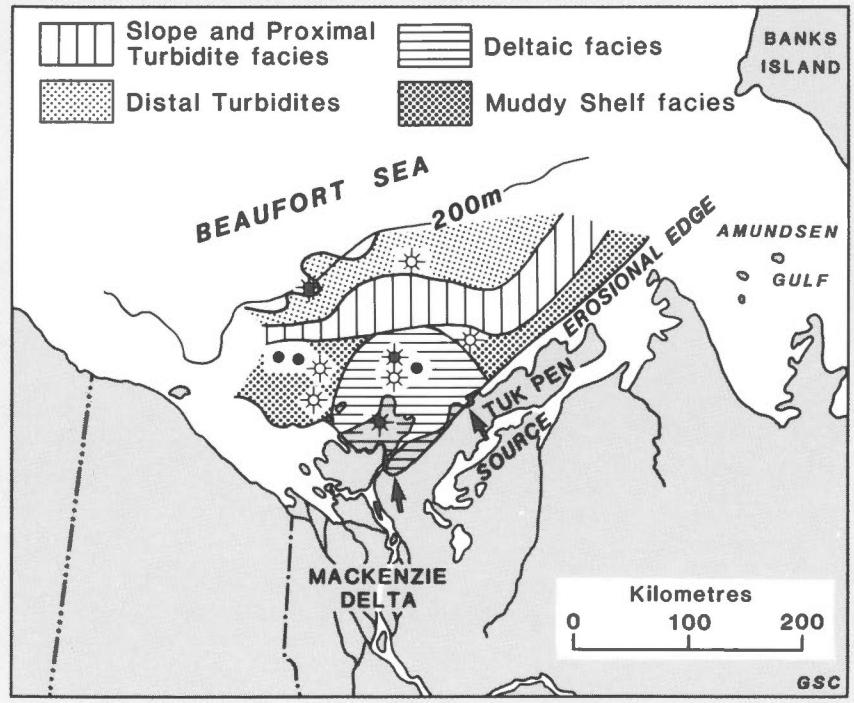


Figure 3.25 Paleoenvironments of the Kugmallit sequence

Known Hydrocarbon Occurrences To date 26 fields have been discovered in Tertiary reservoirs; five oil, thirteen gas, and eight oil and gas. Major accumulations of gas have been found in the Taglu and Issungnak fields (with estimated recoverable reserves of 70 billion and 71 billion cubic metres of gas respectively). The Tarsiut field is one of the larger oil accumulations discovered to date (with estimated reserves of 23.8 million cubic metres of oil).

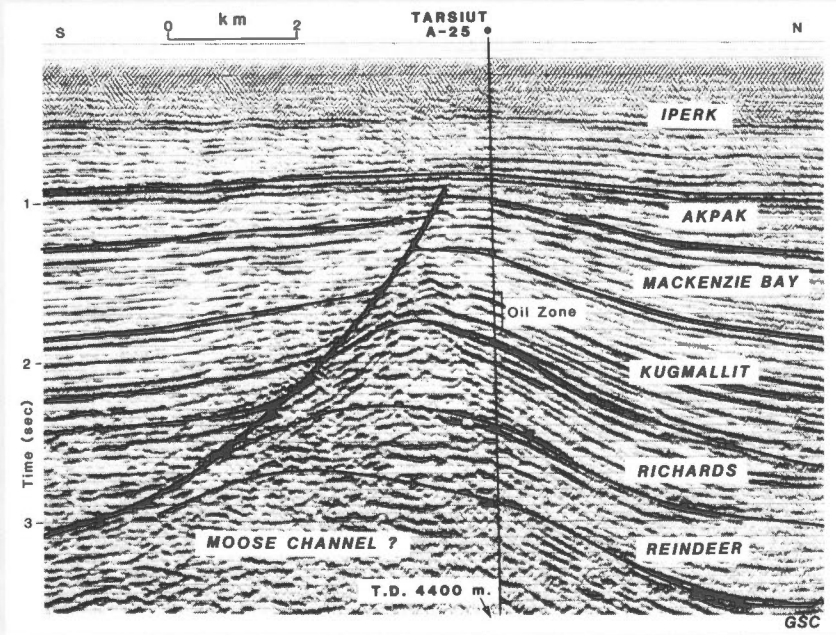


Figure 3.26 Seismic section through Tarsiut Field

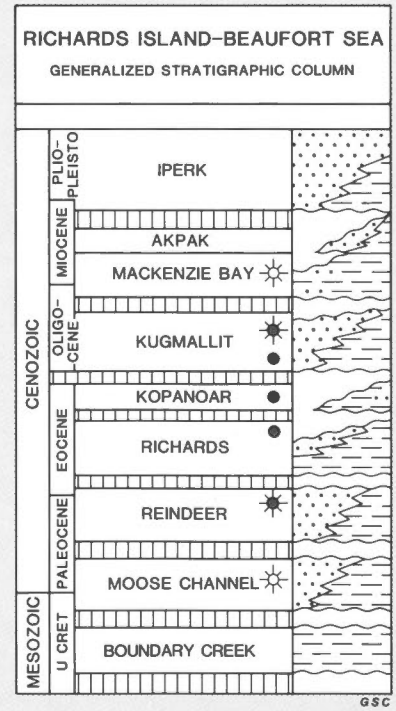


Figure 3.27 Richards Island-Beaufort Sea

ARCTIC ISLANDS

Introduction

Four major tectono-stratigraphic regions are differentiated making up the geological framework of the Canadian Arctic Islands region. The sediments in the various basins represent all geologic systems between Precambrian and recent. With the exception of the youngest sediments, which have not been deeply buried, and the oldest sediments which have not been adequately tested, all the depositional successions have yielded indications of hydrocarbons. The four tectono-stratigraphic regions (see Figure 3.29) considered to be potentially petroleum bearing are the Arctic Stable Platform, the Arctic Fold Belt, the Sverdrup Basin, and the Arctic Coastal Plain. Estimates of potential have been made for the first three regions. The Arctic Coastal Plain is known to contain thick (12 000 m) accumulations of sediments of favorable facies, but the geographic remoteness, and the large proportion of the basin that lies beneath the shifting Arctic Ocean icepack has effectively removed the region from possible economic exploitation. Consequently there exists a minimum of geological data on which to base an assessment.

Reserves

Exploration to date has resulted in eighteen discoveries including ten gas, three oil, and five oil and gas fields. Several of these discoveries are large enough to imply economic viability, however, a number are too small to justify a transportation system under anticipated economic conditions. Because

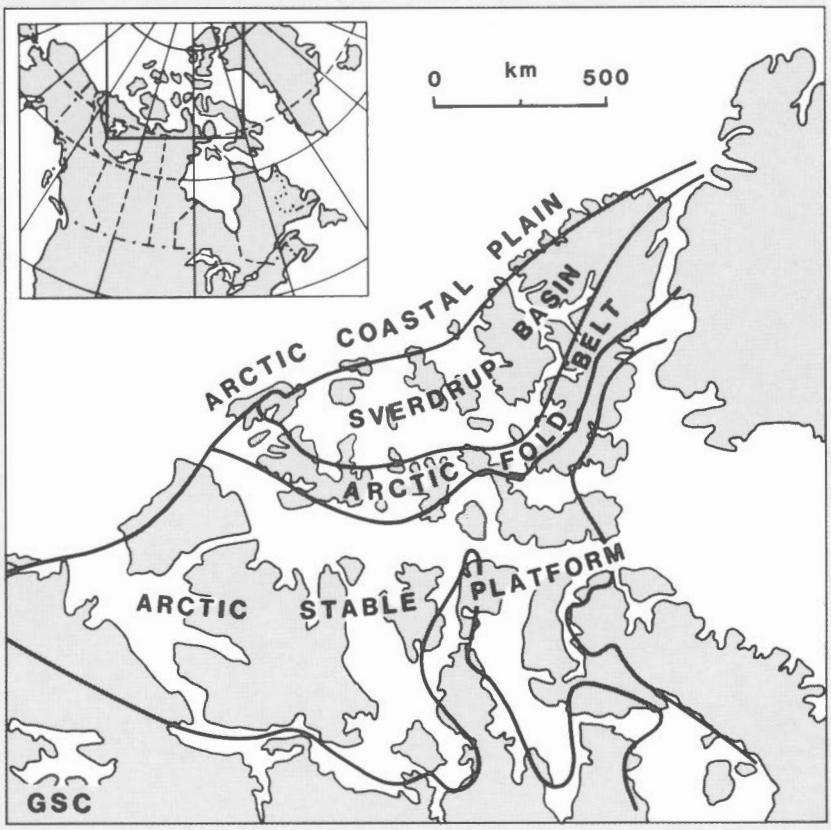


Figure 3.29 Arctic Islands assessment areas

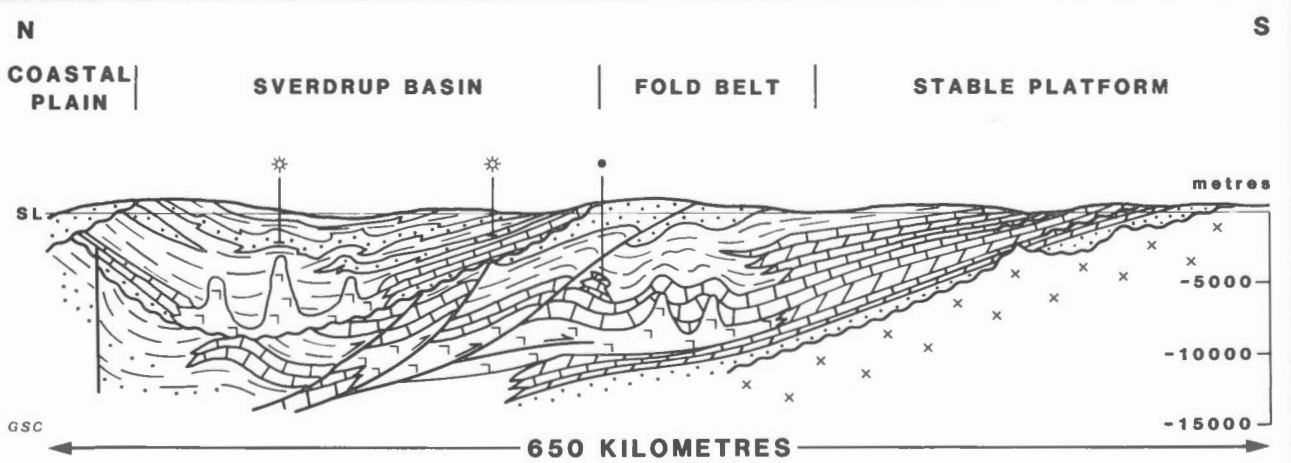


Figure 3.28 Schematic stratigraphic relationships, Arctic Islands

none of the discoveries has been fully delineated, and because of the uncertainty associated with their economics, use of the expression established reserves could be misleading. The values expressed in Table VII are, therefore, labelled "best current estimates" of "discovered resources". The values given reflect quantities that can be considered likely to exist on the basis of existing control plus a subjective opinion of surrounding geology. As such, they represent a necessarily conservative series of estimates that will change as new information is added by delineation drilling and from analysis of pool performance. Discovered resources listed in Table VII do not include natural gas liquids (NGLs), although there are indications that significant quantities of NGLs may be recovered from some gas fields when they are placed on production.

Potential

The Arctic Islands Region is estimated to contain undiscovered potential resources of 686 million cubic metres of oil and 2257 billion cubic metres of gas (average expectation) as shown in Table VIII. Oil potential is estimated to be highest in the Sverdrup basin, in both Mesozoic and Late Paleozoic rocks. Recent oil discoveries provide a better understanding of the controls of oil accumulation and added encouragement for its occurrence. Opportunities for future gas discovery also are considered greatest in the Sverdrup basin. To date, most of the diagnostic exploratory wells have tested a limited number of very prolific plays in the Mesozoic part of the basin. Deeper parts of the Mesozoic succession and a number of relatively untested Late Paleozoic plays are estimated to have at least as much potential as those that have been tested.

Throughout the Arctic Islands region, there are many untested plays, most of which would be under intense exploration if they were located in Southern Canada. The remoteness, logistic difficulties and resultant high costs have contributed to a relatively slow pace of exploration in the Arctic frontier. Several hundred more wildcat wells would be required to provide a reliable evaluation of the region's full potential.

Economic and Environmental Considerations

The tendency for the Sverdrup Basin to yield mostly natural gas has been confirmed through the discovery of large quantities of natural gas relative to oil. Choice of development and operating systems in the Arctic is necessarily tentative at this time. Consequently, development and operating costs are uncertain, as are transportation costs, whether by marine tanker or pipeline mode. Costs of producing hydrocarbons, which are likely to be located primarily offshore will be a function of water depths, the harsh climatic conditions, and reservoir characteristics. In the region of land-fast ice, where ice does not move significantly over long periods of time, there are drilling cost advantages relative to the Beaufort Sea because drilling can take place from reinforced ice platforms. In 1983 dollars, cost per metre for offshore exploratory drilling ranges between $4-$5 thousand whereas drilling onshore in the Arctic ranges between $3-$4 thousand per metre. These costs are indicative of the relative high development investment required in the Arctic. By way of comparison, costs in the Arctic Islands offshore could be 10 to 15 times higher than for resources located in western Canada. However, this comment must be qualified in that reserves found per metre drilled have been greater in the Arctic than in western Canada.

As in the Beaufort Sea, producing hydrocarbons from the Arctic Islands is on the technological frontier. In both areas, it may be necessary to use pilot projects to demonstrate that reserves can be produced and delivered to market on a year round basis, or even seasonally, with some degree of reliability.

Environmentally, there is a concern over the impact that major oil spills could have on the aquatic animals. Tanker modes are generally considered to have greater potential impact on the environment than pipelines. There appears to be a greater degree of uncertainty regarding the impact of environmental damage in the Arctic Islands than other frontier regions. This is due to a relatively incomplete understanding of the physical environmental, factors such as bathymetry, soil conditions, permafrost, etc.

TABLE VII
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL 10^6m^3	GAS 10^9m^3
Cisco	48.7	4.4
Drake West	—	98.5
Hecla	—	85.5
Jackson Bay	—	22.7
King Christian	—	17.3
Kristoffer	—	27.1
MacLean	3.0	13.6
Other discoveries (listed by name only)	24.4	22.8
TOTAL	76.1	360.6

Other discoveries
Balaena
Bent Horn
Cape MacMillan
Char
Roche Point
Romulus
Sculpin
Skate
Wallis

TABLE VIII
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
Arctic Stable Platform	55	175	348
Arctic Fold Belt	36	86	156
Sverdrup Basin	210	426	1035
TOTAL	*316	686	*1305

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
Arctic Stable Platform	85	239	467
Arctic Fold Belt	90	218	355
Sverdrup Basin	880	1800	3483
TOTAL	*1100	2257	*3662

* These numbers do not add arithmetically but must be summed using statistical techniques

ARCTIC STABLE PLATFORM

Area 780 000 square kilometres; approximately 370 000 square kilometres onshore; 410 000 square kilometres offshore.

Geology A blanket of sedimentary rocks up to 3000 metres in thickness overlies ancient crystalline rocks and represents a long period of quiet deposition in shallow epicontinental seas (Figure 3.31). Subsequent to their deposition, they have remained essentially undeformed. Early clastic sediments transgressed over the largely crystalline basement to be followed by mainly carbonate sediments of the shallow epicontinental seas. Breaks in the sedimentary record resulted from eustatic changes in sea level which also controlled the position of various changes in facies of the carbonate sediments. The rocks range in age from Cambrian to Devonian.

Drilling History The first well to be drilled on the Stable Platform was Panarctic *et al* Garnier 0-21 during the summer of 1971. Since then 19 additional wells have been drilled on the Stable Platform.

Potential Source Rocks No seeps have yet been reported from the area although many geologists have reported bitumen-like residues and or fetid petroliferous odors in freshly broken rocks. Limited organic geochemistry indicates high wet gas and good extract yields locally from shales and associated carbonates of the Silurian Cape Phillips Formation which are the deeper water equivalents of the Allen Bay to Read Bay carbonates.

Potential Reservoir Rocks Basal sandstones are poorly consolidated and usually have good porosity in outcrop. Vuggy porosity occurs in many of the carbonates which also can be enhanced by leaching related to unconformity surfaces. Reef; carbonate banks and associated debris flows also may be the loci of porosity development (Figure 3.30).

Known Hydrocarbon Occurrences There are presently no known reserves of either natural gas or oil on the Stable Platform.

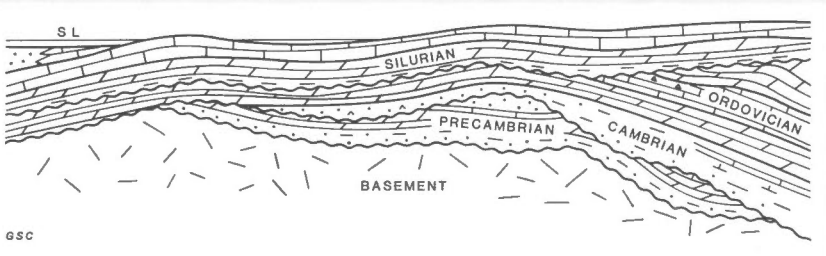


Figure 3.30 Stratigraphic trap configurations in platform stratigraphy

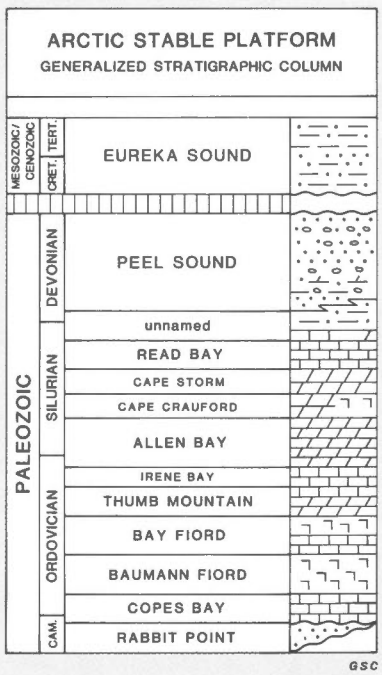


Figure 3.31 Arctic Stable Platform

ARCTIC FOLD BELT

Area 240 000 square kilometres; approximately 150 000 square kilometres onshore, 85 000 square kilometres offshore.

Geology The region is underlain by a wedge of Paleozoic carbonate rocks and equivalent shales thickening from a variable hingeline with the widespread rocks of the Stable Platform region into a deeper basin (Figure 3.33). In ways similiar to the Western Canada Sedimentary Basin, there are rapidly changing sedimentary facies with shales interfingering with carbonates near the so-called "hingeline" of the basin. Reef buildups occur between the carbonates of the shelf and the muds of the deeper basin. The youngest sediments represent interlaced clastic wedges derived from early phases of the Late Devonian — Early Carboniferous Ellsmerian Orogeny. The region is one of complex structures combining detachment folds and thrusts produced during compression modified by vertical movement of evaporites in response to both sediment loading and tectonic stress (Figure 3.32).

Drilling History The first well drilled in the Arctic Islands was drilled within the Fold Belt at Winter Harbour Melville Island during 1962. Since then only 32 wells have tested plays in this region.

Potential Source Rocks No seeps have been reported, however bitumen filled vugs are common in early Paleozoic carbonate rocks. Organic rich shales are common within Ordovician, Silurian, and Devonian sequences which could represent moderate to excellent source rocks.

Potential Reservoir Rocks Reservoir rocks exist in the Ordovician platform sequence, in reefal carbonates adjacent to the shale basin, and in the upper Devonian clastic rocks. Shale intervals above the reservoir rocks should serve as seals for any reservoired hydrocarbons.

Known Hydrocarbon Occurrences In the Bent Horn 'field' on Cameron Island, oil was encountered in reefal carbonates of Devonian age. The Winter Harbour well on Melville Island tested 1.7 thousand cubic metres per day of natural gas from upper Devonian clastic rocks.

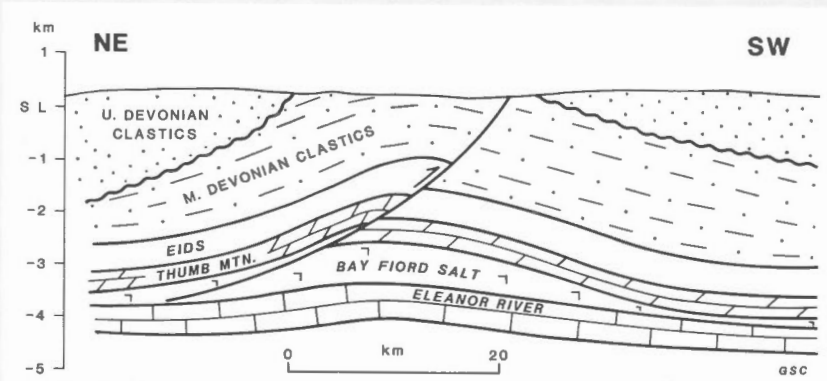


Figure 3.32 Structural traps above and below evaporites

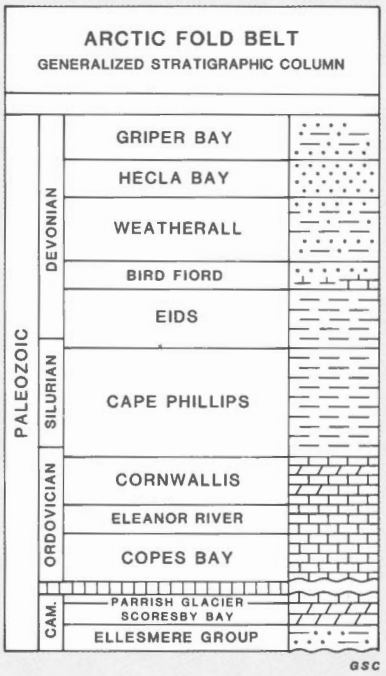


Figure 3.33 Arctic Fold Belt

SVERDRUP BASIN

Area 313 000 square kilometres; approximately 145 000 square kilometres onshore; 168 000 square kilometres offshore.

Geology The greater part of the basin has been filled with approximately 13 000 metres of sediments and minor intrusions of basic sills and dykes. The rocks range from Carboniferous (Visean) to Tertiary in age. Early sediments consisted of carbonate rocks deposited around the margins of the basin with a thick evaporite sequence deposited in the basin centre (Figure 3.28). Later deposition was dominated by the influx of clastic sediments derived from the continental interior and deposited in major deltaic complexes. The complex distribution of clastic facies resulted from the interaction of sediment supply and changes in sea level. The basin was developed on deformed rocks of the Franklinian geosyncline and were themselves deformed during the early Tertiary Eurekan orogeny.

Drilling History (to 1983) One hundred and fourteen wells (88 exploratory) have been drilled, twenty-eight of which were drilled offshore.

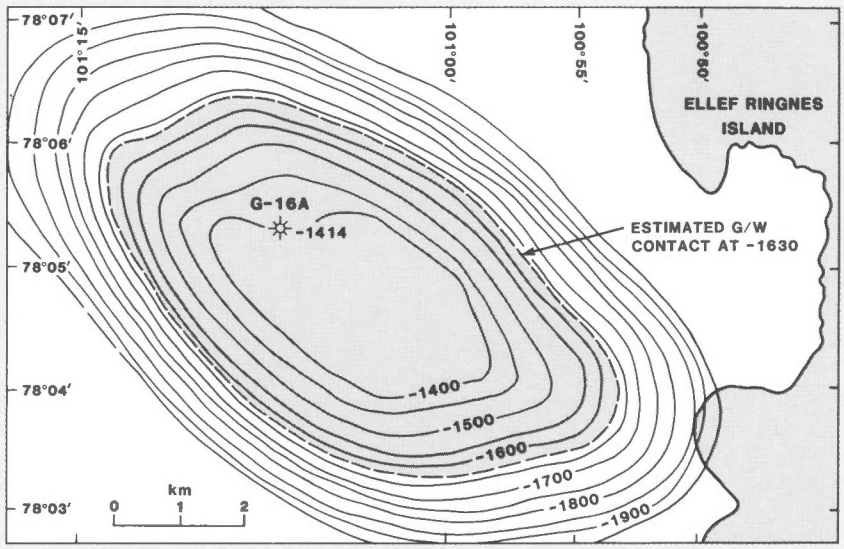


Figure 3.34 Structure contour map on Heiberg Group Jackson Bay Field. Contours in metres

Potential Source Rocks The source rocks for the hydrocarbons found to date, have been identified as the organic rich shales within the Late Triassic Hoyle Bay Formation. Maturation studies indicate that the thermally mature zone for this source rock, mimics the shape of the basin with locally developed overmature areas overprinted on the regional distribution.

Potential Reservoir Rocks Reservoir quality sandstones are developed within the Isachsen, Awingak, Heiberg, Schei Point, and Bjorne stratigraphic units of Mesozoic age; and in both Carboniferous and Permian sequences. Potential carbonate reservoirs are inferred from outcrop sections to occur in the late Paleozoic successions.

Known Hydrocarbon Occurrences Seventeen discoveries or significant shows have been found to date that indicate a reserve at a best current estimate of 76 million cubic metres of recoverable oil and 361 billion cubic metres of marketable natural gas.

Pool Size Three of the natural gas discoveries are estimated to fall into the 50-100 billion cubic metres size range; the largest oil pool is currently estimated to contain approximately 50 million cubic metres. None of the accumulations can be considered fully delineated.

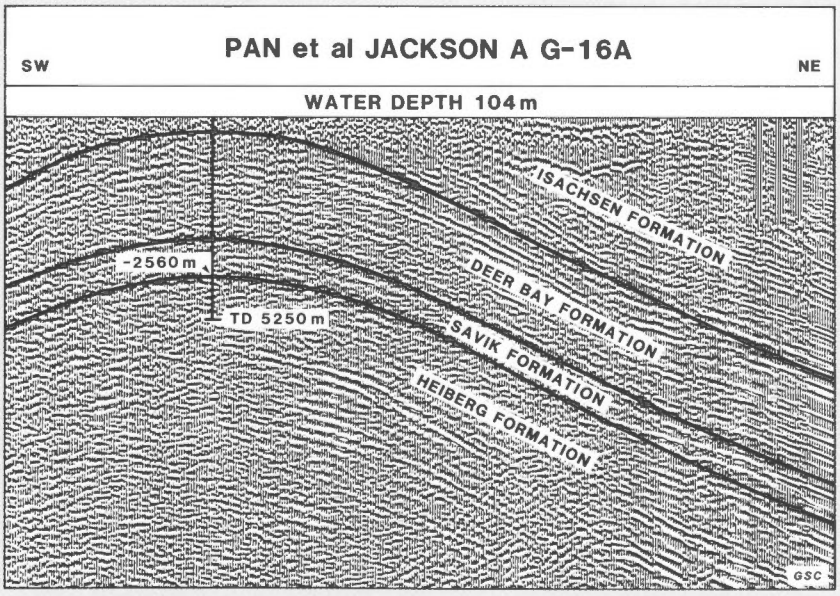


Figure 3.35 Seismic section through Jackson Bay Field

EASTERN CANADA OFFSHORE

Introduction

Sedimentary basins on the continental margin of eastern Canada trend northeast from Georges Bank to the Grand Banks then north-northwest to Baffin Bay a total distance of about 5500 km. There are five main depocentres along this trend. The Scotian Basin which reaches from eastern Georges Bank to the western Grand Banks, the East Newfoundland Basin which contains the giant Hibernia oil and gas field, the Hopedale and Saglek Basins on the Labrador margin and Baffin Bay, Figure 3.36. These basins are flanked and separated by a series of positive elements which include the Yarmouth Arch, the Avalon Uplift, the Cartwright Arch and Davis Strait High.

Although the basins are progressively younger northward, each formed through passive margin tectonics and subsidence with subsequent outbuilding of clastic wedges. All of the offshore regions with thicknesses more than one kilometre are considered to have potential for oil and gas occurrence. Although some Paleozoic rocks are present on the margin, the major hydrocarbon potential is within the thick Mesozoic and Cenozoic sequences which predominate. More specifically the most significant occurrences to date have been in the upper Jurassic-lower Cretaceous clastic sequences with adjacent shales providing the oil and gas source.

Reserves

Exploration to date has identified several large gas and oil discoveries, plus numerous presently non-economic accumulations. Because none of the discoveries has been fully delineated, plus the economic uncertainties associated with their development, the volumes of gas and oil shown in Table IX are considered as best current estimates of discovered resources rather than the more conventional term of established reserves. Values shown are necessarily conservative but are considered technically recoverable, without consideration of economic constraints.

The tabulation of discovered resources includes several recent discoveries. For the fields listed, the values reflect quantities currently thought to be demonstrated with reasonable confidence; as additional delineation drilling occurs, some of the fields could well turn out to be two or three times larger than currently shown.

Potential

The assessed portion of the East Coast basins include Georges Bank, the Scotian Shelf, Grand Banks South, East Newfoundland Shelf, Labrador and Southern Baffin Island shelves,

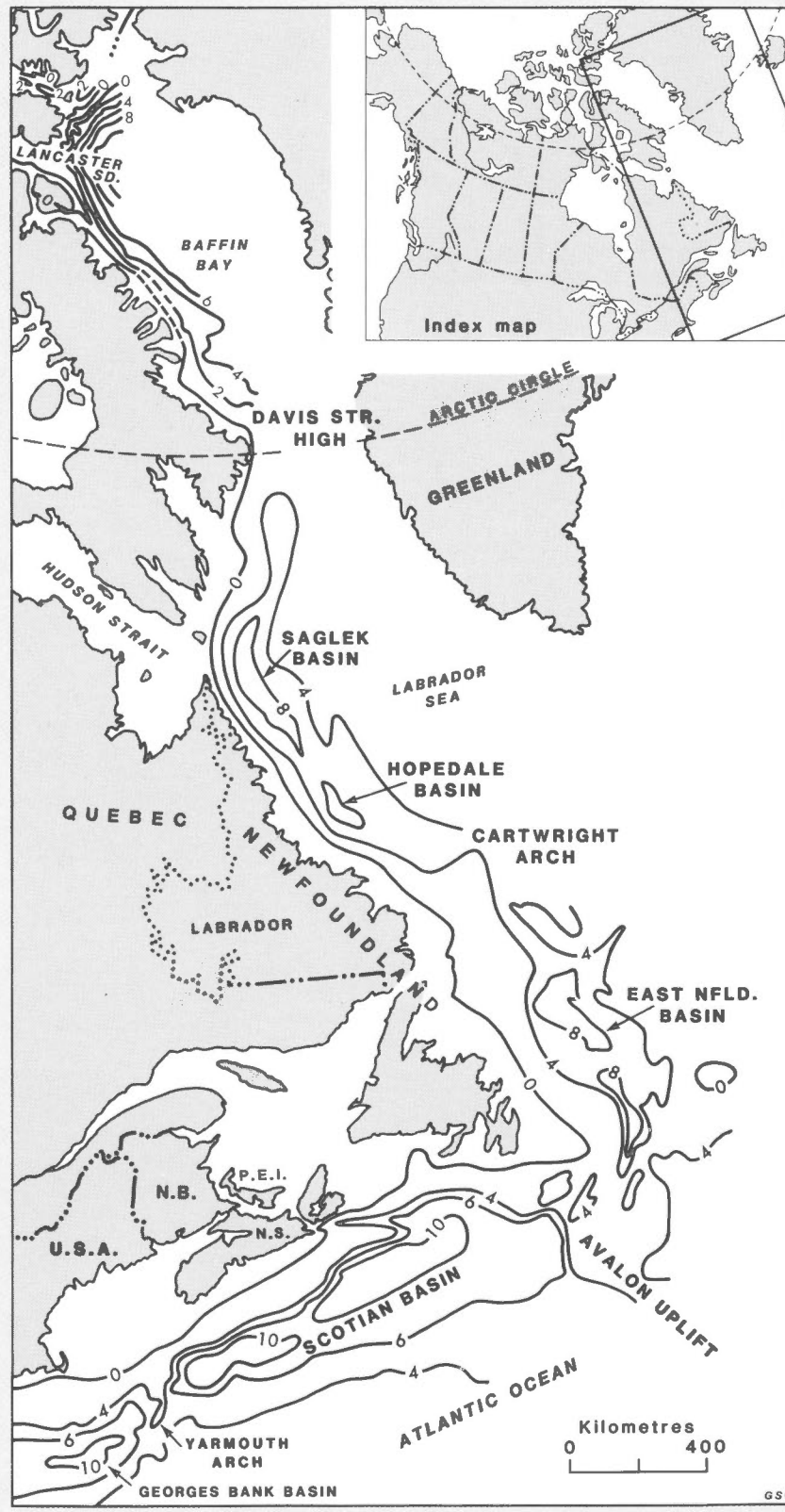


Figure 3.36 Index map of offshore basins showing total Mesozoic-Cenozoic sediment fill in kilometres (after Purcell *et al* 1980)

plus the East Newfoundland Basin, Baffin Bay and Lancaster Sound. These areas are estimated to contain more than 2400 billion cubic metres of gas and almost 1900 million cubic metres of oil (average expectation) as shown in Table X. Oil potential is considered greatest in the East Newfoundland Shelf and Basin areas with much lower prospects to the north and south. Gas potential is estimated to be greatest in the Labrador Shelf and Scotian Shelf areas. Exploratory drilling to date has been concentrated in three basins, on plays currently viewed as most prospective. Many more plays have yet to be tested, and whole basins such as Baffin Bay and East Newfoundland Basin are virtually untouched. There are numerous opportunities for major and giant size fields yet to be discovered. Shelf area estimates given in Table X include the uppermost or currently accessible parts of the continental slope.

TABLE IX
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL 10^6m^3	GAS 10^9m^3
SCOTIAN SHELF		
(Includes Gulf of St. Lawrence)		
Thebaud	2.2	12.2
Venture	6.4	56.6
Others discoveries (listed)	5.6	42.9
EAST NEWFOUNDLAND		
Hibernia	159.0	56.6
4 other discoveries (listed)	47.8	—
LABRADOR SHELF		
Bjarni, North Bjarni	2.5	43.2
Gudrid	0.5	13.7
Hekja	—	11.8
2 other discoveries (listed)	1.1	8.6
TOTAL East Coast Offshore	225.1	245.6

Other discoveries

SCOTIAN SHELF
- Arcadia
- Banquereau
- Citnalta
- Cohasset
- East Point
- Intrepid
- Olympia
- Onondaga
- Primrose
- Sable Island
- South Venture

EAST NEWFOUNDLAND
- Ben Nevis
- Hebron
- Nautilus
- South Tempest

LABRADOR SHELF
- Hopedale
- Snorri

Economic and Environmental Considerations

Scotian Shelf For the quantities of natural gas that have been discovered in the Sable Island area, studies show that particularly costly circumstances exist. This is due to the location offshore in 20 to 30 metres of water and the composition of the gas. The gas stream will require initial treatment at offshore facilities before being transported by subsea pipeline to a mainland processing plant. Alternatively, liquefied natural gas and gas liquids could be transported by a marine tanker shuttle system.

Exploratory drilling costs in this area are in the range of $7-$10 thousand per metre ($1983). Development of the Venture gas field, based on pipelining to the mainland, has been estimated to cost $2.5-$3.0 billion to allow recovery of 60-90 billion cubic metres of natural gas. A major constraint facing development in this area is the future marketability of natural gas both in Canada and internationally.

Hibernia Discoveries of oil and associated gas have raised the possibility of commercial production from this area by the end of this decade. Studies have been made on possible development, production and transportation systems. Nevertheless, plans are tentative and costs are expected to be high. Cost will be a function of the design required to cope with severe sea, ice and weather conditions, as well as design to allow mobility of development and production platforms. Exploration drilling costs are in the range of $8-$15 thousand per metre. For transportation, the tanker mode is preferred, as pipelining appears impractical due to the physical conditions on the ocean floor. Estimates suggest that development costs for Hibernia will be in the range of $5-$7 billion for a recoverable oil reserve estimated to be between 150 and 250 million cubic metres. In terms of marketability, Hibernia is favourably located in relation to consuming regions, which will serve to minimize transportation costs.

The major environmental risk is an offshore oil spill, whether a consequence of a subsea blowout, damage to subsea production systems or pipelines due to icebergs or tanker collision.

TABLE X
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
Georges Bank	10	168	350
Scotian Shelf**	8	72	139
Grand Banks (South)	2	50	95
East Newfoundland Shelf	300	1128	2190
East Newfoundland Basins	130	270	720
Labrador Shelf	10	134	275
Baffin Bay - Lancaster Sound	5	55	158
TOTAL	*512	1877	*3392

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
Georges Bank	37	150	307
Scotian Shelf**	111	508	991
Grand Banks (South)	20	90	180
East Newfoundland Shelf	170	290	530
East Newfoundland Basin	110	370	900
Labrador Shelf	160	745	1627
Baffin Bay - Lancaster Sound	18	270	803
TOTAL	*725	2423	*4713

* These numbers do not add arithmetically but must be summed using statistical techniques

** Estimates for this area are under review at time of printing

GEORGES BANK

Area Approximately 27 500 square kilometres of Georges Bank, a physiographic feature, lies east of the equidistance line between Canada and the U.S. All of this area is offshore.

Geology Georges Bank Basin underlies the western part of Georges Bank and the southwestern end of the Scotian Basin underlies the eastern part. Between the two lies the Yarmouth Arch, Figure 3.38. Georges Bank Basin is a structural sag approximately 200 x 90 kilometres whose axis trends northeast and plunges southwesterly. The basin formed in the Early Jurassic over a folded and faulted basement complex inset with down-faulted remnants of probable Triassic sediments and volcanics. The basin had its most rapid period of subsidence during the Early and Middle Jurassic when up to four kilometres of predominately carbonate rocks were deposited in a warm shallow epicontinental sea. The carbonates were flanked shoreward by fine and coarse clastics. An additional four kilometres of paralic facies with some shelf edge carbonates were deposited during the balance of the Jurassic and in the Cretaceous and Tertiary Periods.

The Scotian Basin underlies the easternmost 50 kilometres of Georges Bank and contains up to 10 kilometres of sediment fill, nearly half of which may consist of Triassic and lower Jurassic rift valley clastics, salt and sabkha deposits. These are overlain by thick wedges of middle Jurassic through Tertiary clastics. A continuation of the upper Jurassic shelf edge carbonates rims the northwest flank of the Basin.

Drilling History No wells have been drilled in the Canadian part of Georges Bank.

Potential Source Rocks One well on the western Scotian Shelf and two U.S. wells in Georges Bank Basin provide stratigraphic and geochemical control.

The organically richest rocks occur in the Cretaceous and upper Jurassic. Older, deeper rocks which are thermally mature, contain dominantly terrestrial organic matter that is likely to be gas prone. Maturation studies from the nearest Scotian Shelf well indicates probable immaturity to depths of 2100 metres in the middle Jurassic. Because of the rapid deposition and the interfingering of marine and paralic sequences, an average balance of oil and gas source rocks is expected in the Georges Bank area.

Potential Reservoir Rocks The thick Cretaceous and Jurassic sandstones are expected to have good reservoir characteristics. The carbonates will probably be tight unless subjected to leaching and dolomitization. Limited reefoid zones also may occur.

Known and Potential Hydrocarbon Occurrences There are no reserves of either oil or gas on the Canadian part of Georges Bank. Plays within Georges Bank Basin and the Yarmouth Arch are limited to basement related structures. Within the Scotian Basin salt tectonics have created a variety of plays associated with salt diapirs, pillows, growth faults, and stratigraphic traps along the basin flank.

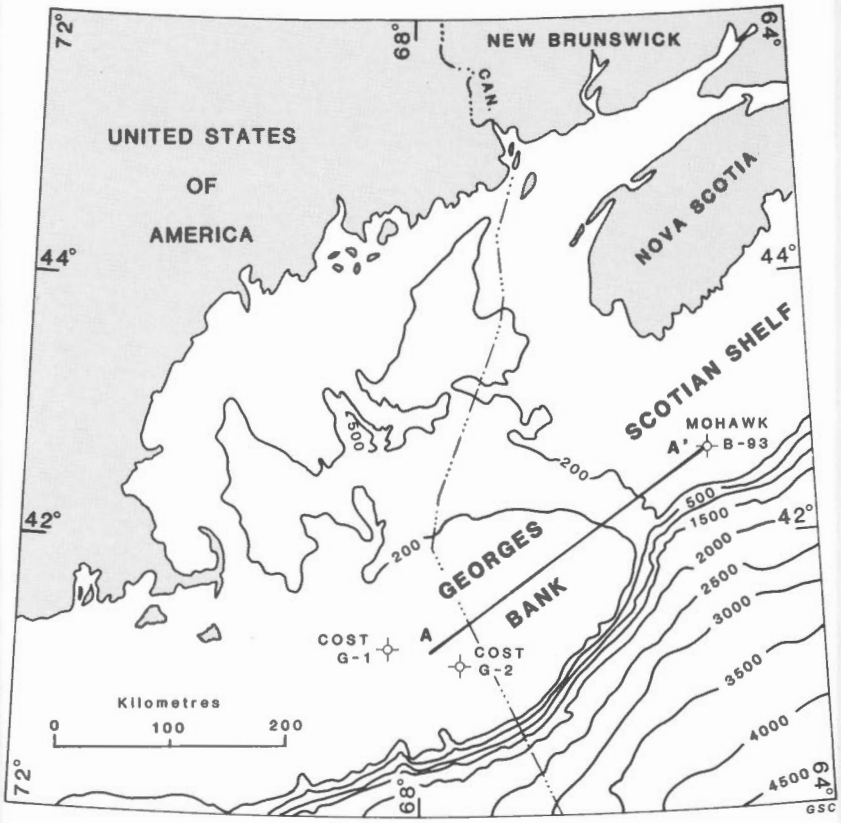


Figure 3.37 Index map of Georges Bank area. Bathymetry in metres

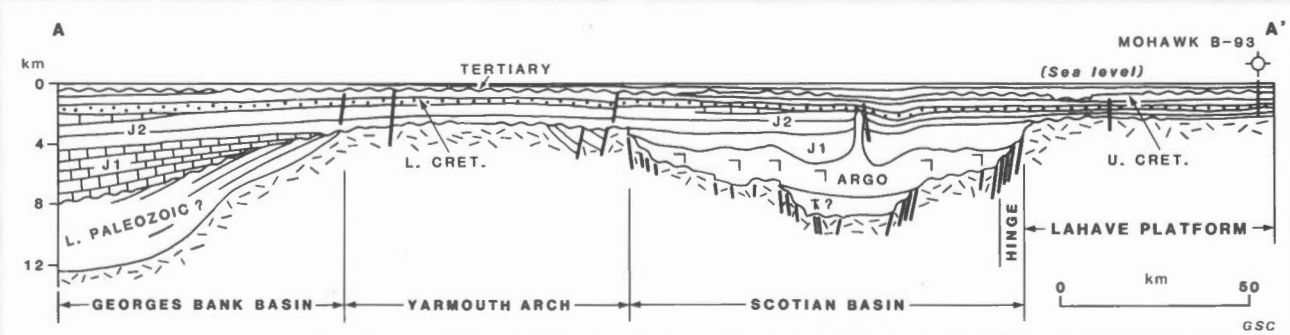


Figure 3.38 Georges Bank structure section (A-A') from Scotian Basin to Georges Bank Basin

SCOTIAN SHELF

Area Approximately 130 000 square kilometres from the centre of Northeast Channel to the centre of Laurentian Channel and from the fall line to the 1500 metre isobath, all offshore.

Geology The main depocentre of the Scotian Basin underlies the eastern part of the Scotian Shelf. It consists of a seaward thickening wedge of Mesozoic and Cenozoic sediments which reaches a maximum thickness of 12 kilometres in the vicinity of Sable Island, Figure 3.40. The oldest sediments are Triassic and Lower Jurassic red clastics, evaporites and sabkha rift basin deposits formed during the early stages of the breakup of the North American and African continental plates. These are overlain by thick middle Jurassic to lower Cretaceous regressive deltaic sequences and shelf carbonates. The upper Cretaceous and Paleogene are marine transgressive units which are succeeded by regressive Neogene clastics, Figure 3.42. The LaHave Platform which forms the northwest flank of the basin has been a relatively stable element accumulating up to four kilometres of low energy clastics and extensive shelf carbonates.

Drilling History The first deep exploratory well was drilled on Sable Island in 1967. It encountered traces of gas and oil at a total depth of 4,604.3 metres. To June, 1983, 79 wells have been drilled on the shelf testing a total of 53 structures.

Potential Source Rocks Extensive geochemical analyses of material from exploratory drilling indicate that, coincident with the depocentre of the Scotian Basin, lowermost Cretaceous and older sediments are thermally mature. In this area, the Verrill Canyon Formation shale, containing Type III organic matter is largely gas prone and has been the source for hydrocarbons trapped in upper Jurassic and lower Cretaceous reservoirs, as at Venture and West Sable Island. The pre-upper Jurassic source rocks, overmature in the basin, may be within the peak generating range on the flanks of the basin. Upper Cretaceous and Tertiary source rocks, with a higher content of Type I and II organic matter are thermally immature.

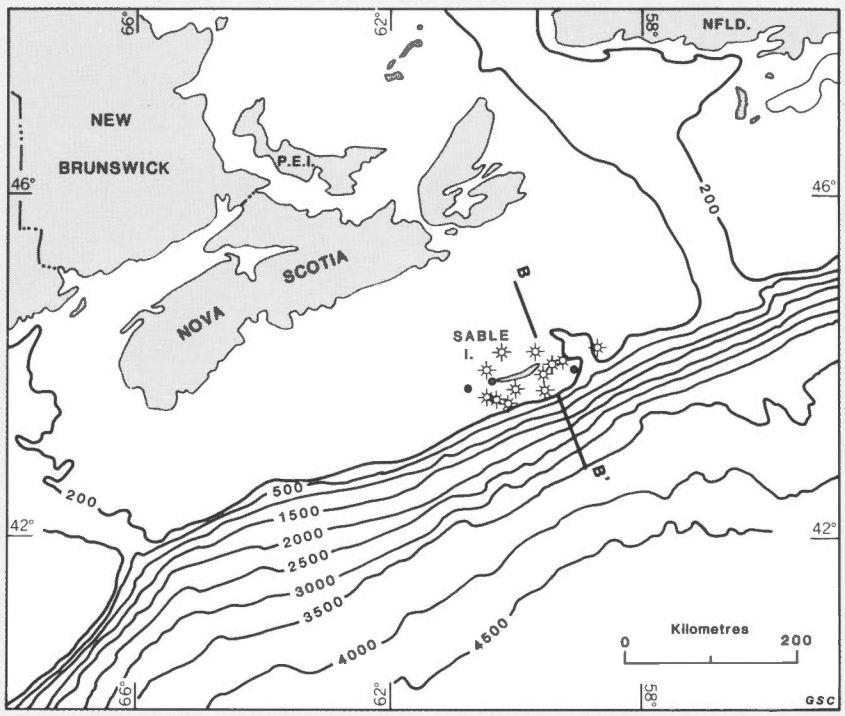


Figure 3.39 Index map of Scotian Shelf showing some of oil and gas discoveries around Sable Island. Bathymetry in metres

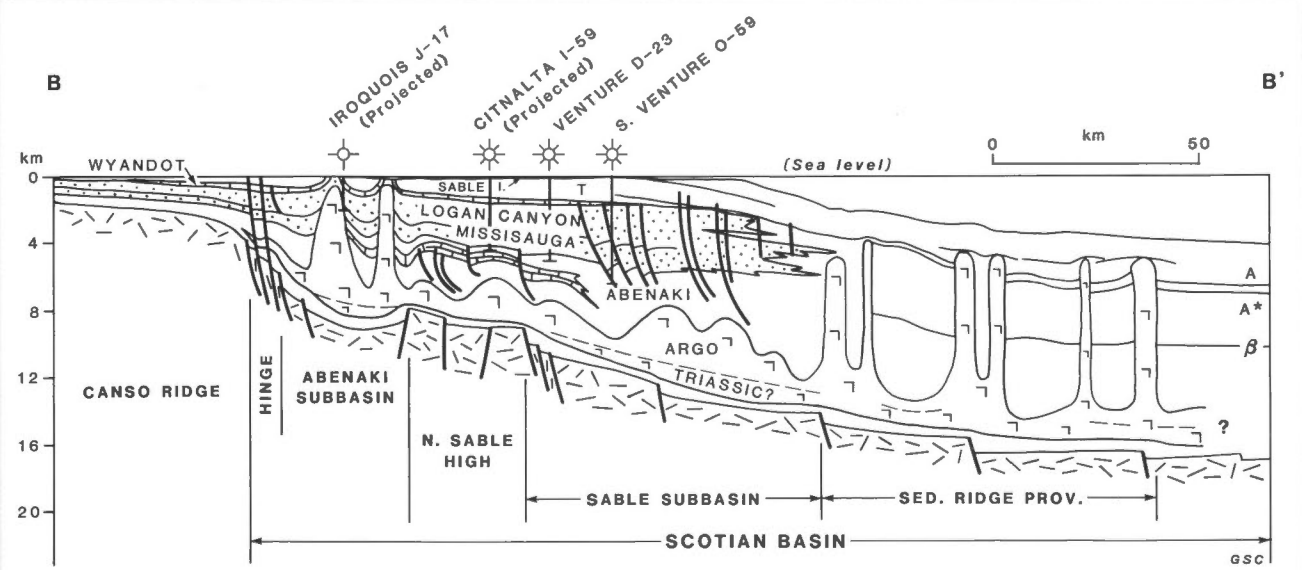


Figure 3.40 Structure section (B-B') across Scotian Shelf

Potential Reservoir Rocks The thick fluvial and deltaic sandstones in the Scotian Basin generally have good porosity and provide excellent reservoirs. The sandstones on the LaHave Platform are generally fine grained and thinner. Ample shale interbeds are available for reservoir seal. The thick shelf carbonates (Abenaki Formation) are generally tight although occasional occurrences of secondary porosity have been noted in wells drilled to date.

Known and Potential Hydrocarbon Occurrences Salt mobilization since the Middle Jurassic has resulted in numerous diapirs and pillows as well as an extensive complex of down-to-basin faults. Such structures have provided the trapping mechanism for eleven significant gas and oil discoveries and seven additional wells with oil and gas shows. The largest accumulation is at Venture where an estimated 57 billion cubic metres of gas has been delineated. Other plays on the Scotian Shelf include basement structures, the carbonate front and stratigraphic traps.

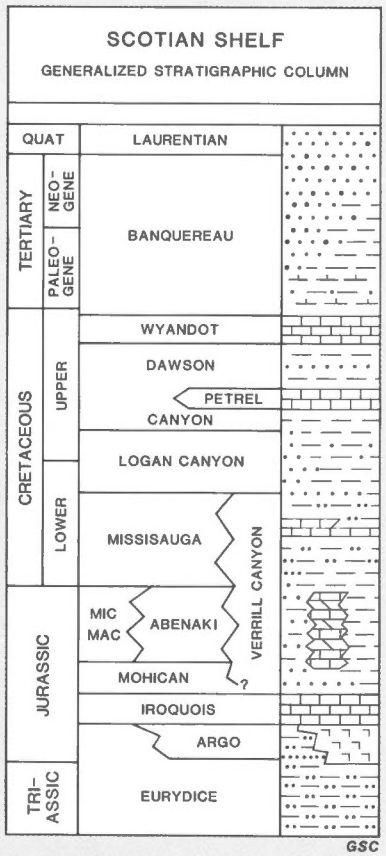
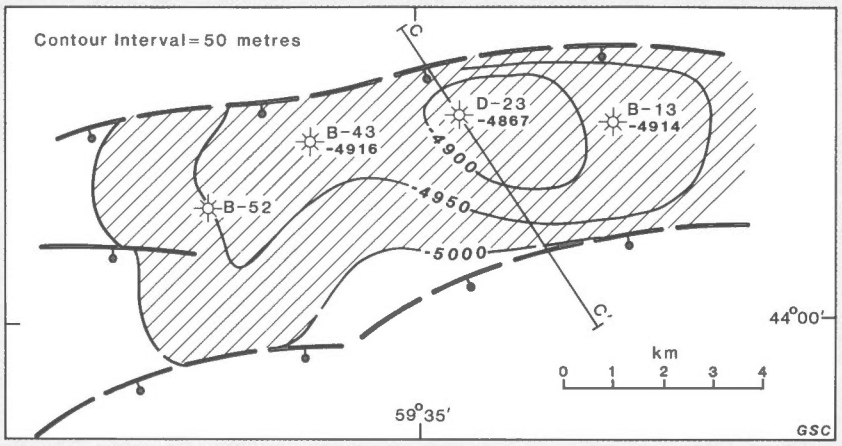


Figure 3.42 Scotian Shelf



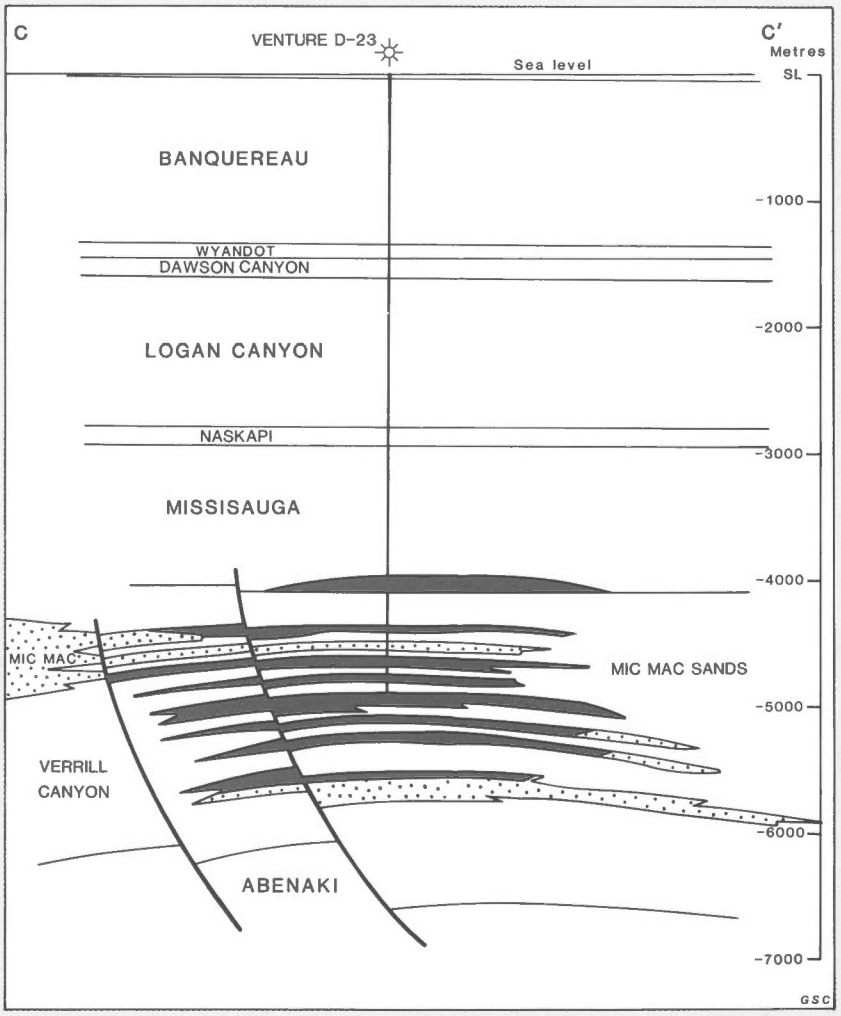


Figure 3.41 Map of Venture Field. Generalized structure section Venture Gas Field. Gas pay shaded solid

GRAND BANKS (SOUTH)

Area Approximately 170 000 square kilometres all offshore.

Geology Thick rift basin and marine deposits occur in structural subbasins, preserved as remnants within the Avalon Uplift, beneath the regional mid-Cretaceous unconformity. This setting developed during the separation of the North American and European continental plates. Basins recognized include Whale, Horseshoe and Carson within the Avalon Uplift and South Whale and Flemish Basins flanking the Uplift, Figure 3.43. Upper Paleozoic and Triassic through upper Jurassic sediments in these subbasins are moderately deformed and have undergone extensive erosion, Figure 3.44. A thin basal transgressive sand overlies the unconformity and is succeeded by up to two kilometres of upper Cretaceous and Tertiary shales and mudstones. In the southern half of the area, these units overlie basement. The eastern extremity of the Scotian Basin, the South Whale Subbasin, lies to the west of the Avalon Uplift and contains thick lower Cretaceous, Jurassic and older successions.

Drilling History The first two exploratory wells Tors Cove and Grand Falls were drilled in 1966. Between 1971 and 1975, 28 additional wells were drilled. No wells have been drilled in this area since 1975.

Potential Source Rocks Upper Cretaceous and Tertiary shales overlying the unconformity have potential as source rocks but are thermally immature. Within the subbasins the lower and middle Jurassic are considered as poor, gas prone source rocks. The Verrill Canyon shale is expected to provide a mature source rock on the west flank of the Avalon Uplift.

Potential Reservoir Rocks The basal transgressive sand, although porous, has no effective up-dip seal. Clastic wedges on the west flank of the uplift are expected to contain porous sands. Some porosity occurs in thin upper Cretaceous limestone units.

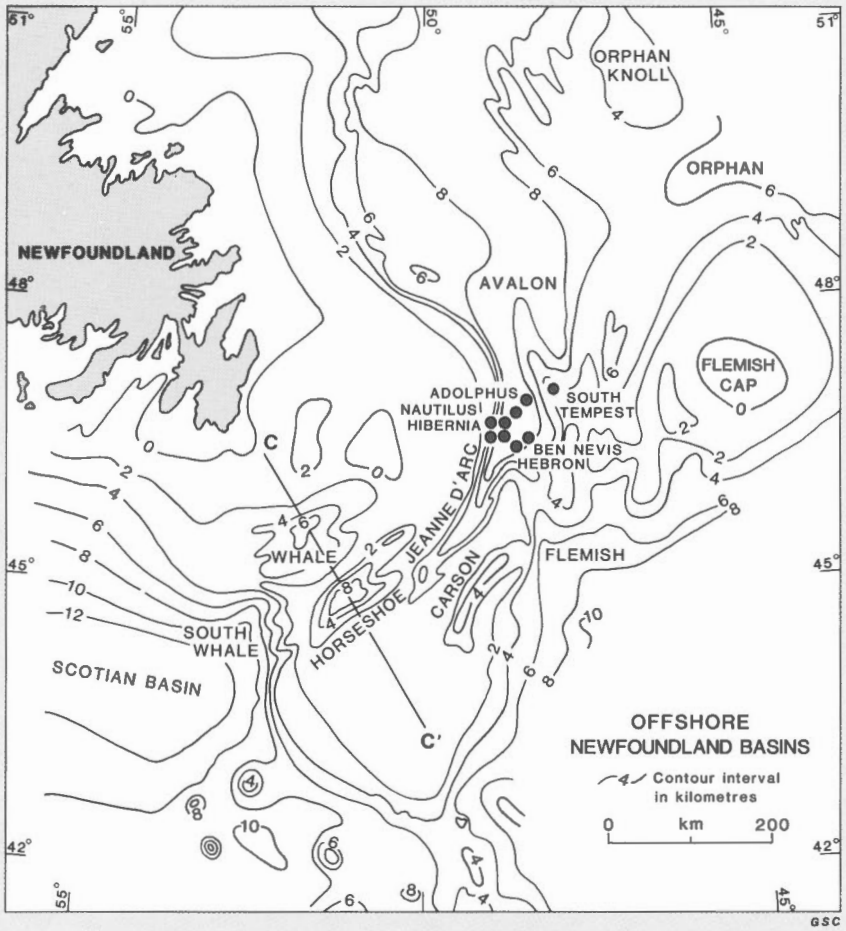


Figure 3.43 Index map for basins in Grand Banks (south), East Newfoundland Shelf and East Newfoundland Basin. Contours indicate depth to basement from sea floor (after McMillan 1982)

Known and Potential Hydrocarbon Occurrences Heavy gravity oil was recovered in Heron H-73, drilled on the flank of a salt diapir in the South Whale Subbasin. Salt structures, together with plays at the unconformity constitute the main opportunities for hydrocarbon entrapment.

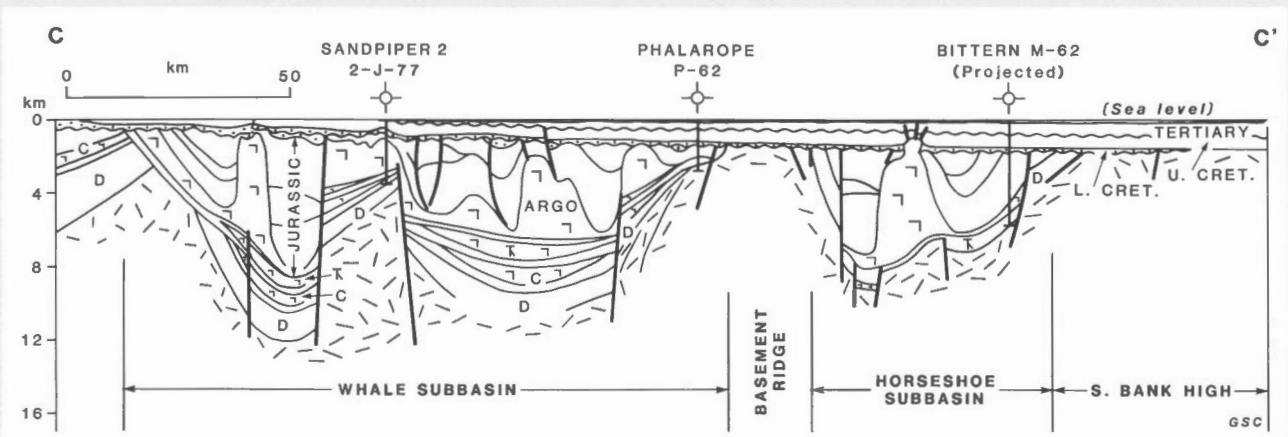


Figure 3.44 Structure section (C-C') through the Whale and Horseshoe subbasins

EAST NEWFOUNDLAND SHELF

Area Approximately 230 000 square kilometres from the inner limit of sediments to the 400 metre isobath between Grand Banks South and the Cartwright Arch (46°-54°N). All offshore.

Geology This area consists of three partly overlapping depocentres and contains a maximum of more than 14 kilometres of sediments. Oldest beds are a fault bounded Carboniferous succession with thick continental clastics and minor carbonate and evaporite units. The Mesozoic basin formed during the breakup of North America and Europe. It is bounded to the west by a major basement hinge zone and to the east by an outer ridge complex, Figure 3.43. Rift basin Triassic and Jurassic sediments are coarse red clastics and evaporites overlain by marine Jurassic facies. The lower Cretaceous syndrift sequences include coarse clastics shed north and east into the Avalon Basin. These are covered by transgressive upper Cretaceous and Tertiary shales with minor sandstone and limestone beds. The Tertiary age depocentre overlaps the other two. It contains up to 5500 metres of predominately mudstones and siltstones.A generalized stratigraphic column is presented in Figure 3.45.

Drilling History The first well in this area was drilled at the extreme southern end of the Jeanne d'Arc subbasin in 1971. Ten additional wells were drilled through 1975 with the only significant show at Adolphus. There was no further drilling until 1979 when the discovery well at Hibernia was drilled. This was closely followed by 13 wells including 5 stepouts at Hibernia. Four of the 8 new wildcats were significant oil discoveries.

Potential Source Rocks An excellent source rock for oil generation has been identified in the Jurassic Kimmeridgian age sequences. All of the oils discovered at Hibernia, Ben Nevis and the Adolphus oil show have been tentatively correlated to this source. These oils indicate a higher level of maturation than has so far been encountered in the source rocks indicating migration from deeper in the basin. Older Jurassic rocks are low in organic carbon content while overlying Cretaceous and Tertiary sediments are terrestrialy domained and largely immature.

Potential Reservoir Rocks Basal clastics and carbonates in the upper Paleozoic and lower part of the Mesozoic may provide some reservoirs in areas where they are shallow enough to be drilled. Upper Jurassic and lower Cretaceous synorogenic clastic rocks have demonstrated good porosity in wells drilled on the west and east flanks of the Avalon Basin but they occur above the oil maturation window. The transgressive upper Cretaceous and Tertiary section contains reservoir beds, but they occur above the oil maturation window.

Known and Potential Hydrocarbon Occurrences The giant Hibernia oil and gas field lies adjacent to the hinge zone on the flank of the Avalon Basin, Figure 3.47. Best estimate for reserves of gas and oil are 55 billion cubic metres and 160 million cubic metres respectively. The structure is a large rollover anticline associated with the hinge zone, Figure 3.46. Other plays include basement and salt related structures, a complex zone of faulting associated with a south-east trending hinge zone across the Avalon Basin and stratigraphic traps both at the mid Cretaceous unconformity and on the basin flanks. Four wells, Ben Nevis, Nautilus, South Tempest, and Hebron have encountered substantial oil accumulations in these plays.

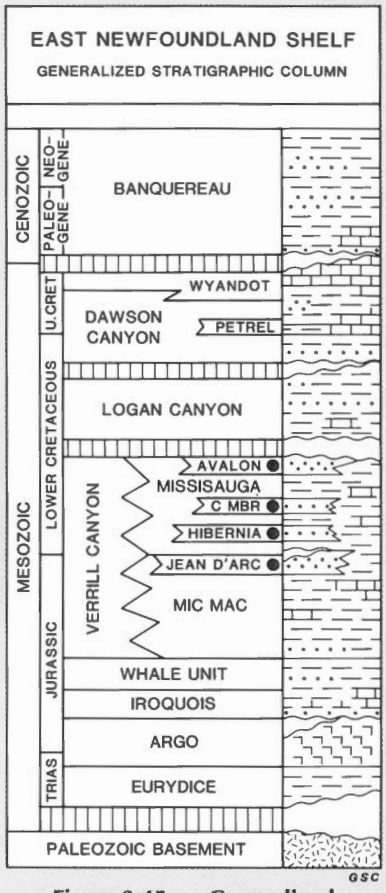


Figure 3.45 Generalized stratigraphic column for East Newfoundland Shelf.

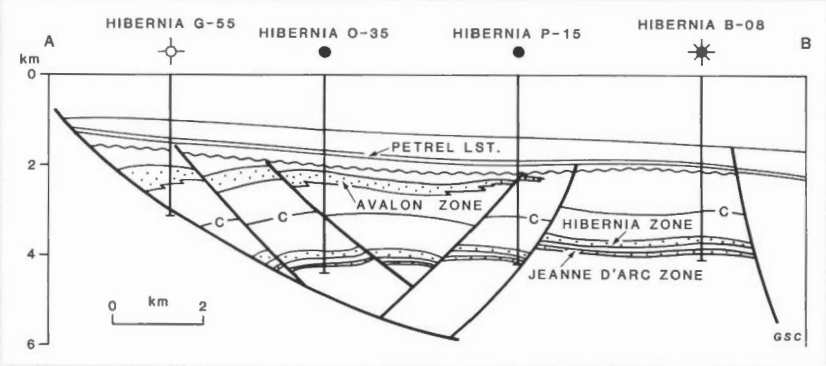


Figure 3.46 Structural cross-section across Hibernia Oil Field showing main oil bearing zones. Line of section indicated on Figure 3.47 (after Benteau and Sheppard 1982)

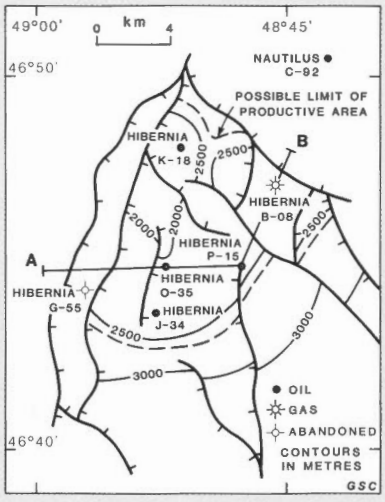


Figure 3.47 Map of Hibernia Oilfield (after Benteau and Sheppard 1982)

EAST NEWFOUNDLAND BASIN

Area Approximately 130 000 square kilometres from the 400 metre isobath to the limit of the continental realm at Orphan Knoll and Flemish Cap to Cartwright Arch. All deep water.

Geology This area (Figure 3.43) is closely related to the adjacent shelf in that it contains the distal parts of all three depocentres, Figure 3.48. The upper Paleozoic sediments are strongly block faulted and overlain by lower Cretaceous-Jurassic sediments that were deformed and locally eroded at the time of continental breakup. They are unconformably overlain by the upper Cretaceous and Cenozoic deep water sediments. Based on the results of one well, five regional unconformity bounded sequences are recognized in this area, Figure 3.49. The Paleozoic and lower Cretaceous beds are shallow marine whereas overlying sequences through Late Tertiary are all deep water deposits.

Drilling History Only one well, Texaco *et al* Blue H-28 has been drilled in this area. It was drilled in 1979 in 1,486 m of water to a total depth of 6,088 m below sea level.

Potential Source Rocks Geochemical analyses suggest mature oil source rocks occur in the Cretaceous sediments. The overlying Cenozoic beds are marginally mature. The underlying Paleozoic section is strongly overmature indicative of earlier burial and subsequent erosion. The thick additional Mesozoic section indicated from seismic data to occur off structure should be fully mature. Lower Cretaceous and Jurassic sediments probably occur in this basin, however, organic matter type is unknown.

Potential Reservoir Rocks Porous sandstone reservoir beds were encountered in the Cretaceous but they were water bearing. Only limited porosity occurs in the Paleozoic sandstones. Undrilled Cretaceous and Jurassic strata can be expected to contain reservoir quality beds.

Known and Potential Hydrocarbon Occurrences There are no known hydrocarbon occurrences in this area, however, there are a number of undrilled basement related structures capped by thick Tertiary shales. A number of stratigraphic trapping possibilities occur on the flanks of these structures and at the mid- and upper Cretaceous unconformities.

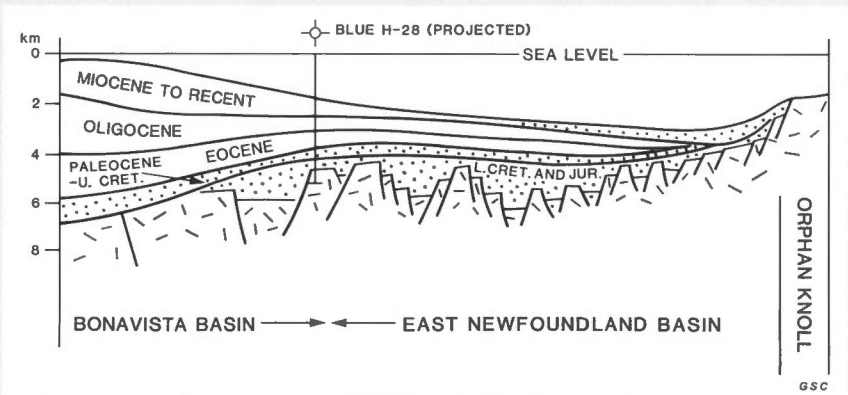


Figure 3.48 Schematic E-W cross-section across East Newfoundland Basin (see Figure 3.43 for location of Orphan Knoll)

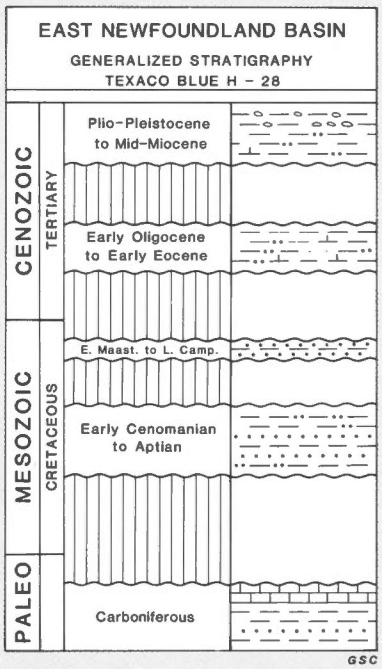


Figure 3.49 Lithology and age of sediments in Texaco *et al* Blue H-28

LABRADOR SHELF

Area Approximately 180 000 square kilometres from the Cartwright Arch to Davis Strait High, and between the western edge of sediments and the 400 metre isobath, all offshore.

Geology Two depocentres, the Hopedale and Saglek Basins underlie the Labrador Shelf. In the Hopedale Basin, a seaward thickening wedge of Tertiary silty and sandy mudstones overlies an inner shelf graben in which syntectonic lower Cretaceous volcanics and arkosic sandstones and upper Cretaceous and lower Tertiary shales were deposited over a block-faulted Paleozoic and Precambrian basement complex. Within the basement complex, there are outliers of Paleozoic carbonates and clastics that provide reservoir rocks. Locally it is possible that the Cretaceous volcanics geophysically mask older Mesozoic sediments as well as the Paleozoic sequences. The Saglek Basin off the Hudson Channel was a Tertiary depocentre and contains up to 10 kilometres of sediments.

Drilling History The first well, Tenneco *et al* Leif E-38, was spudded in 1971 and completed two years later. Since that time drilling has continued slowly (due to a short period each year when ice and weather conditions permit drilling operations) to the present total of 23 wells drilled and three in progress.

Potential Source Rocks Gas and condensates have been discovered in five wells in the Hopedale Basin. Geochemical analyses indicate the condensates are broadly related, and the product of a Type III (terrestrial) kerogen. However, the level of thermal maturation in the wells is generally low suggesting migration of the hydrocarbons from deeper in the basin.

Potential Reservoir Rocks In the Hopedale Basin, the lower Cretaceous Bjarni sandstone and the Freydis, Gudrid and Leif sand members in the overlying regional shale formations, Figure 3.51, are all of reservoir quality. Locally, reservoir also occurs in the Paleozoic carbonates underlying the coastal plain sequences as at the Gudrid and the Hopedale discoveries. Fluvial and marine sandstone units of Cretaceous and Early Tertiary age are expected to provide the main reservoirs in the Saglek Basin.

Known and Potential Hydrocarbon Occurrences There are five gas and condensate discoveries and one oil show in the Hopedale Basin. All are related to basement highs which is the major play in this basin, Figure 3.52. However, stratigraphic traps also may occur in conjunction with the depositional limits of the reservoir units. On the north flank of the Saglek Basin, Aquitaine *et al* Hekja discovered gas in a folded Paleocene sandstone reservoir. This well, with approximately 40 metres of net pay, is the most northerly discovered accumulation of hydrocarbons on the Atlantic margin.

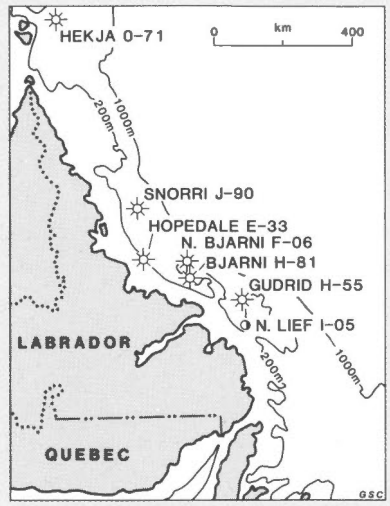


Figure 3.50 Location map Labrador Shelf

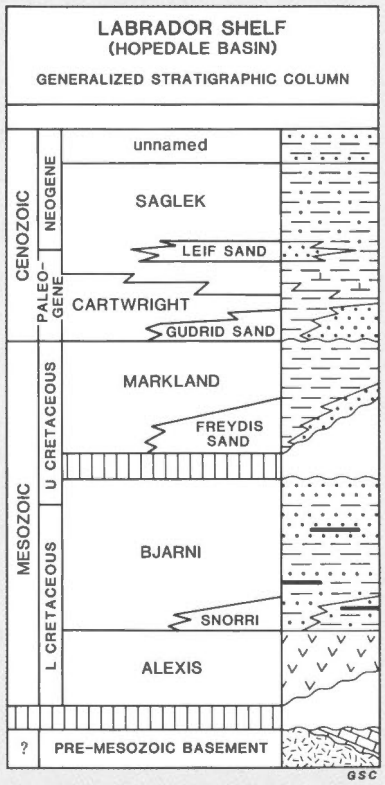


Figure 3.51 Generalized stratigraphy of the Hopedale Basin (Umpleby 1979)

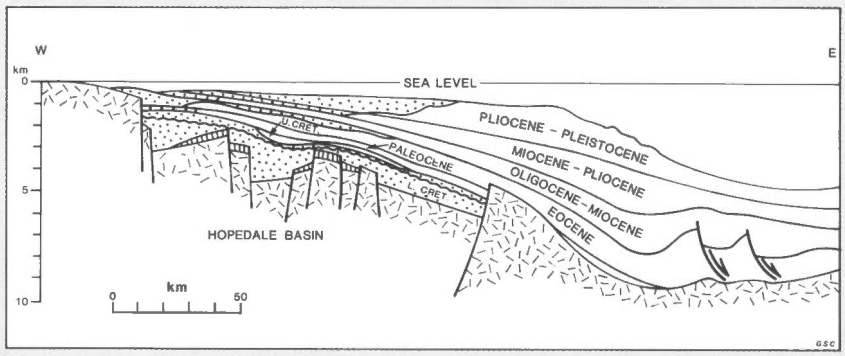


Figure 3.52 Schematic cross-section across Labrador Shelf (Umpleby 1979)

BAFFIN BAY

Area Approximately 305 000 square kilometres from Davis Strait High to Kane Basin. It includes 2000 square kilometres onshore Bylot Island.

Geology The sedimentary geology of offshore Baffin Bay is poorly known but seismic data indicate two areas of relatively thick deposition. At Home Bay, a wedge of Tertiary and possible upper Cretaceous shales and sandstones, up to four kilometres thick, overlies continental Precambrian and Mesozoic oceanic basements. Tertiary volcanics present in the Davis Strait area, may occur in the subsurface of Home Bay. To the north a depocentre of interpreted Tertiary and upper Cretaceous sediments, in excess of 12 kilometres in thickness occurs at the mouth of Lancaster Sound. This unit extends westward, across a sill of Paleozoic carbonates, into Lancaster Sound where it is preserved in a half graben, Figure 3.54.

Drilling History There are no wells in this area.

Potential Source Rocks Source rocks have not been identified in Baffin Bay but a small active oil seep is known from a submarine trough in the Scott Inlet area. Significant thicknesses of sediment, including probable marine Tertiary beds, increases the likelihood of some source rocks being present in the northern part of Baffin Bay.

Potential Reservoir Rocks Tertiary and upper Cretaceous sandstone reservoirs are expected throughout the area as well as lower Mesozoic and Paleozoic clastics and Paleozoic carbonates along the inner shelf.

Known and Potential Hydrocarbon Occurrences No wells have been drilled on the Canadian margin of Baffin Bay. A drilling program off Greenland failed to find any hydrocarbons. Prospects in this area include structures related to basement fault blocks and ridges, possible down-to-basin faults in areas of rapid Tertiary sedimentation and stratigraphic traps along the basin margin.

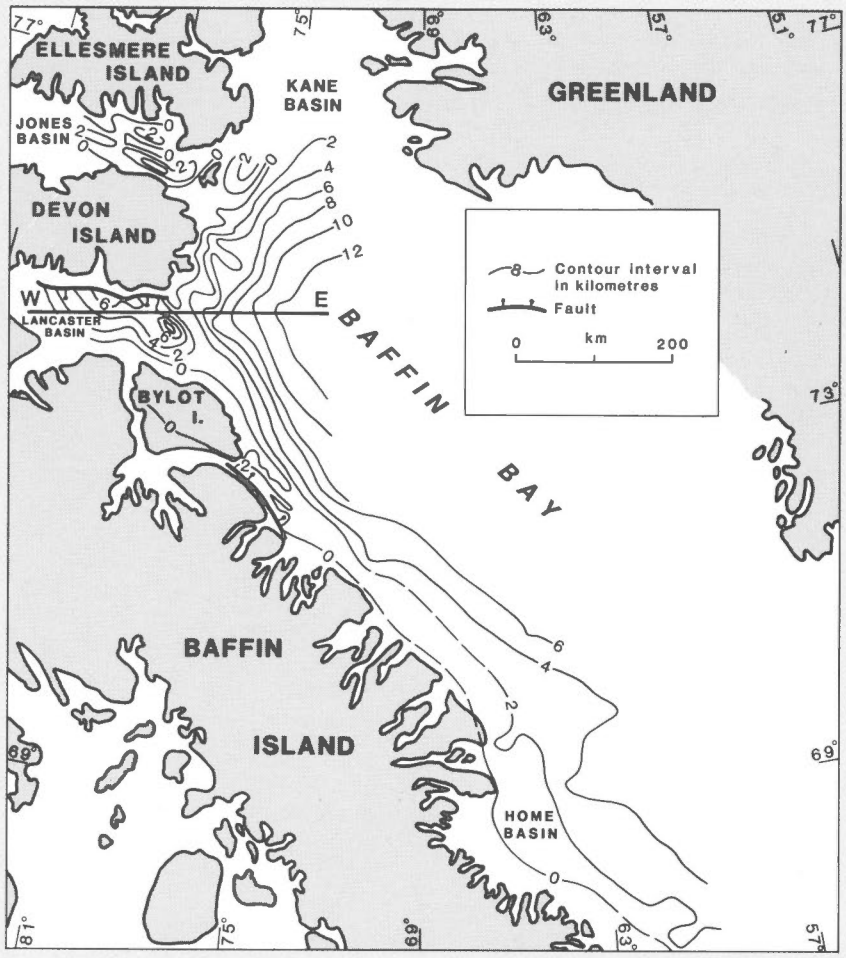


Figure 3.53 Depth to basement map of Baffin Bay. Zero contour indicates limits of Mesozoic-Cenozoic sediments (after Hea *et al* 1980)

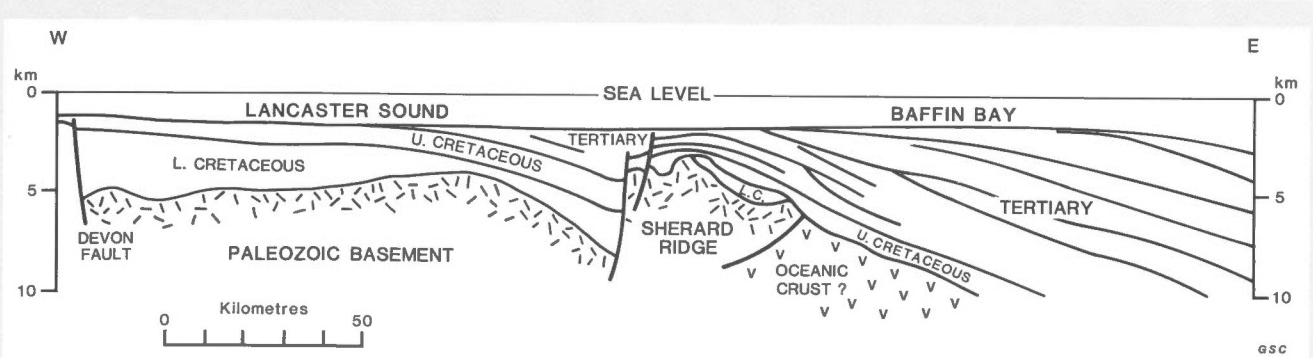


Figure 3.54 Structure section from Lancaster-Sound through to Baffin Bay (after Hea *et al* 1980)

PALEOZOIC BASINS — EASTERN CANADA

Introduction

Between the Western Canada Sedimentary Basin and the basins of the Atlantic offshore, there are several sedimentary regions within or flanking the Canadian Shield. The largest of these is the Paleozoic Hudson Bay Basin within the Hudson Platform. To the south, Paleozoic rocks of the St. Lawrence Lowlands cross southern Ontario and extend northeast along the valley of the St. Lawrence to northwestern Newfoundland. To the east, upper Paleozoic rocks of the successor Maritimes Basins underlie the southern Gulf of St. Lawrence and adjacent areas, Figure 3.55.

Numerous small gas and oil fields occur in peninsular southern Ontario. Two small accumulations, one of gas and one of oil and gas have been discovered in the Magdalen Basin. Estimates of potential have been made for each of the major regions, however, in the case of the Hudson Platform, with only three wells and limited seismic data in more than a 600 000 square kilometres offshore area, this assessment is based on a minimum of geological data.

Reserves

In southern Ontario, the remaining reserves as of 1982 were 836 thousand cubic metres for recoverable oil and 8.8 billion cubic metres for gas.

Potential

Estimates of oil and gas potential for each of the Basins are given in Tables XI. Only southern Ontario can be considered adequately explored. Potential is considered greatest in the Hudson Platform for both oil and gas. Drilling targets for all basins are thought to be small relative to other frontier regions and consequently have had limited and sporadic exploration. The amount of drilling and geophysics in Hudson Bay is too sparse to encourage more active exploration, and the geological understanding of all basins (except southern Ontario) is inadequate to predict the hydrocarbon potential with confidence, hence the speculative values could be significant.

Figure 3.55 Index map of Paleozoic Basins of Eastern Canada. Contours indicate sediment fill in kilometres

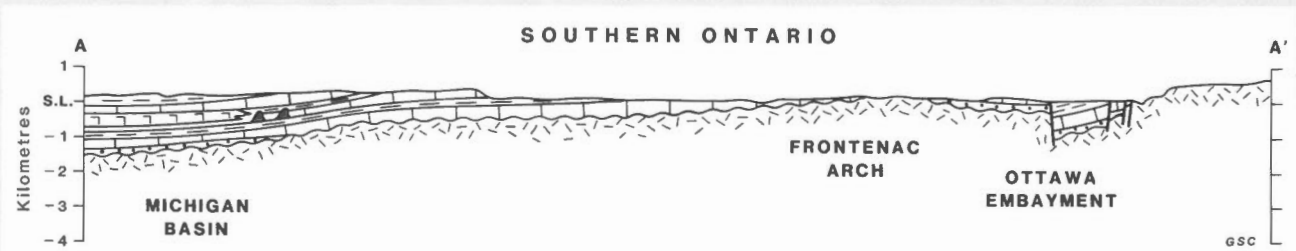


Figure 3.56 Schematic section across southern Ontario

TABLE XI
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL ($10^6 m^3$)	High Confidence	Average Expectation	Speculative Estimate
St. Lawrence Lowlands	4	17	52
Hudson Platform	10	130	560
Maritimes Basins	3	20	95
TOTAL	*20	167	*605

GAS POTENTIAL ($10^9 m^3$)	High Confidence	Average Expectation	Speculative Estimate
St. Lawrence Lowlands	10	60	150
Hudson Platform	10	90	400
Maritimes Basins	20	40	290
TOTAL	*46	190	*660

* These numbers do not add arithmetically but must be summed using statistical techniques

ST. LAWRENCE LOWLANDS

Area Approximately 293 000 square kilometres of which 160 000 square kilometres is offshore in the Great Lakes and the northern Gulf of St. Lawrence.

Geology Paleozoic rocks extend in a narrow belt from peninsular southern Ontario, along the St. Lawrence River, to the northern Gulf of St. Lawrence and includes Anticosti Island, and parts of Gaspe and northwestern Newfoundland, Figure 3.56. In southern Ontario, the stratigraphy consists of the marginal and shallow marine facies of the adjacent Allegheny and Michigan Basins and includes basal sandstones, shelf carbonates with attendant reef and evaporite facies, and shales. Maximum thickness is less than two kilometres, Figure 3.55. Coeval, but much thicker (up to six kilometres) sequences of carbonates and clastics occur in the Anticosti Basin.

Drilling History Drilling began in southern Ontario in 1858 with discovery of the Oil Springs field. Since then, over 40,000 wells have been drilled. Numerous wells have been drilled along the St. Lawrence River with no significant success. More recently exploration has moved into offshore Lake Erie where more than 1000 wells have been drilled. The Gaspe region has had a long, but sporadic exploration history as has Anticosti Island and Western Newfoundland.

Potential Source Rocks Hydrocarbons in the numerous gas and oil fields in southern Ontario have probably migrated from the adjacent basins but indigenous source rocks may occur in Ordovician marine bituminous shales, and Silurian reefs. In the Anticosti Basin, Ordovician shales and basinal equivalents of the Silurian carbonates are the likely sources of numerous seeps and minor shows.

Potential Reservoir Rocks Sandstones as well as porous carbonates are reservoir rocks in southern Ontario. Similar shelf carbonate and clastic facies have exhibited porosity in the other areas.

Known and Potential Hydrocarbon Occurrences Across southern Ontario, more than a hundred small gas and oil fields occur in rocks ranging from Cambrian to Devonian age. Plays include deformation and updip truncation of Cambrian sandstone and dolomite reservoirs; dolomitization of Ordovician carbonates; updip pinchouts of lower Silurian sandstones; many middle Silurian pinnacle and patch reefs, Figure 3.57 and dolomitization of middle Devonian carbonates. Oil seeps were recorded as early as 1812 in western Newfoundland and 1836 in Gaspe Subsequent drilling in both areas recorded only small non-commercial accumulations.

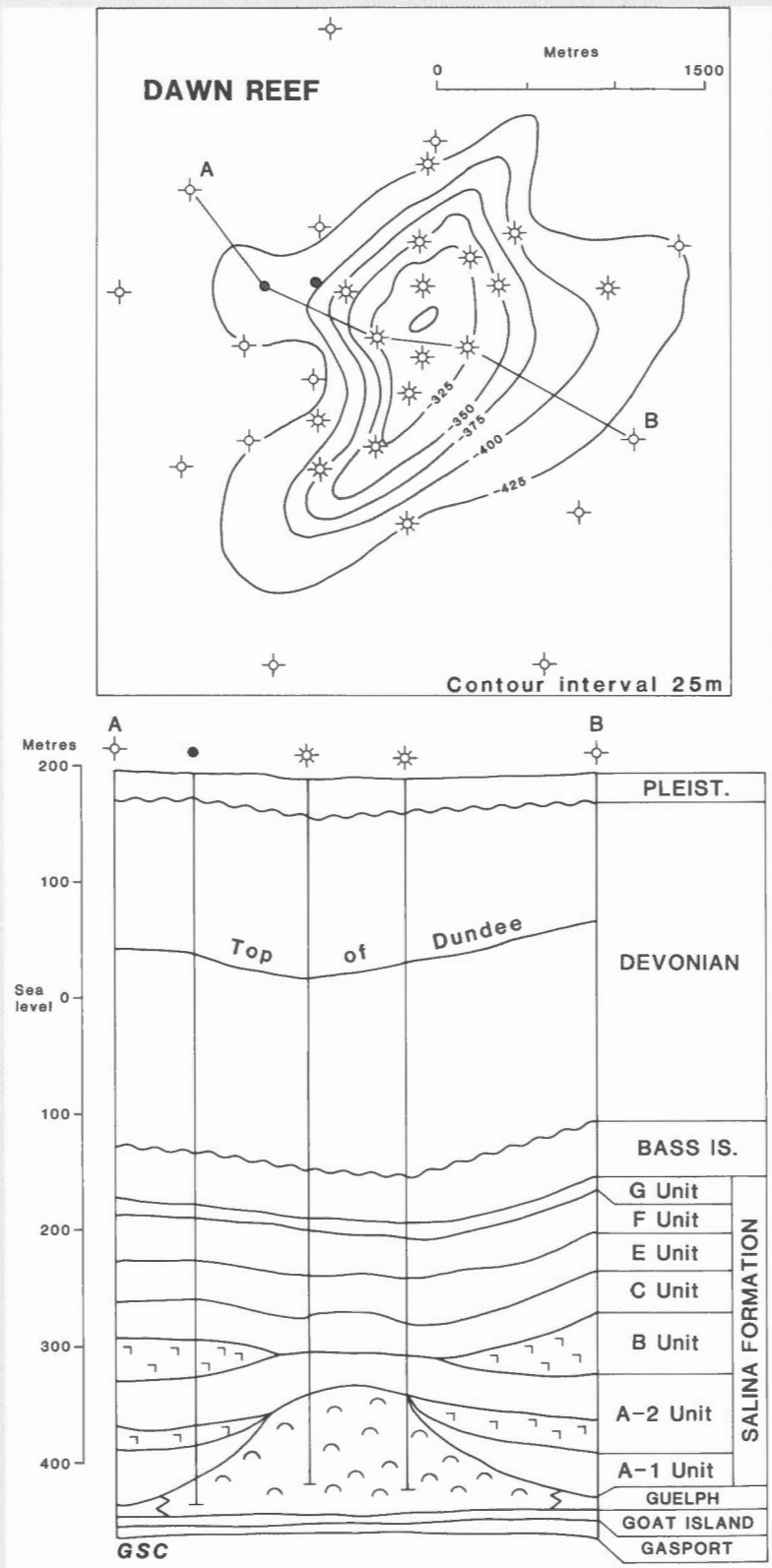


Figure 3.57 Structure map and section of the Dawn Reef of southern Ontario, typical of the small patch reef type of trap

HUDSON PLATFORM

Area Approximately 1 000 000 square kilometres of which less than a third is onshore.

Geology The Paleozoic rocks of the Hudson Platform are contained in four large but shallow depressions within the Canadian Shield, Figure 3.55. The outcrop patterns indicate these are erosional remnants of a much broader original cratonic cover, Figure 3.59. All are essentially carbonate basins with a variety of facies including small reefs. Some shales, evaporites and sandstones also occur, Figure 3.58. Maximum sedimentary thickness occurs in Hudson Bay Basin where up to two kilometres of sedimentary rocks are known.

Drilling History Several holes were drilled in the onshore areas of the Moose River and Hudson Bay Basins in the 1940's. In 1969, Aquitaine *et al* Walrus was drilled in the offshore. Two additional wells were drilled offshore in 1974. There has been one well drilled in both Foxe Basin and Ungava Bay.

Potential Source Rocks There are no known oil seeps from the rocks in the Hudson Platform although bitumen has been reported from vugs associated with Ordovician reefs. Intervals of black petroliferous shale occur within the Ordovician and Devonian successions. The latter yielded 18 litres per tonne on distillation. There were traces of oil and gas reported from two of the offshore wells although thermal maturation of organic matter appears very low.

Potential Reservoir Rocks The main reservoir beds will be intercrystalline vuggy or reefoid intervals within carbonate formations with seal provided by tight carbonates, shale or evaporite facies.

Known or Potential Hydrocarbon Occurrences There are no known hydrocarbon reserves in this area. Plays would include structures related to basement uplifts, faults, salt, drape over reef buildups, etc. With random porosity developed within regional carbonate formations, stratigraphic traps will be common.

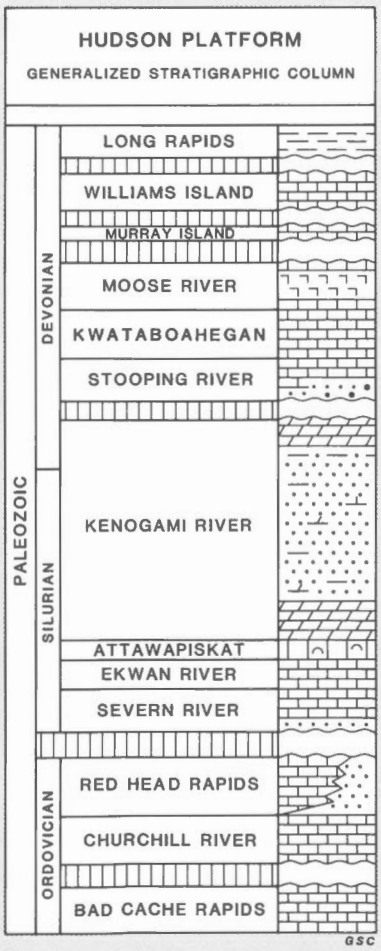


Figure 3.58 Hudson Platform

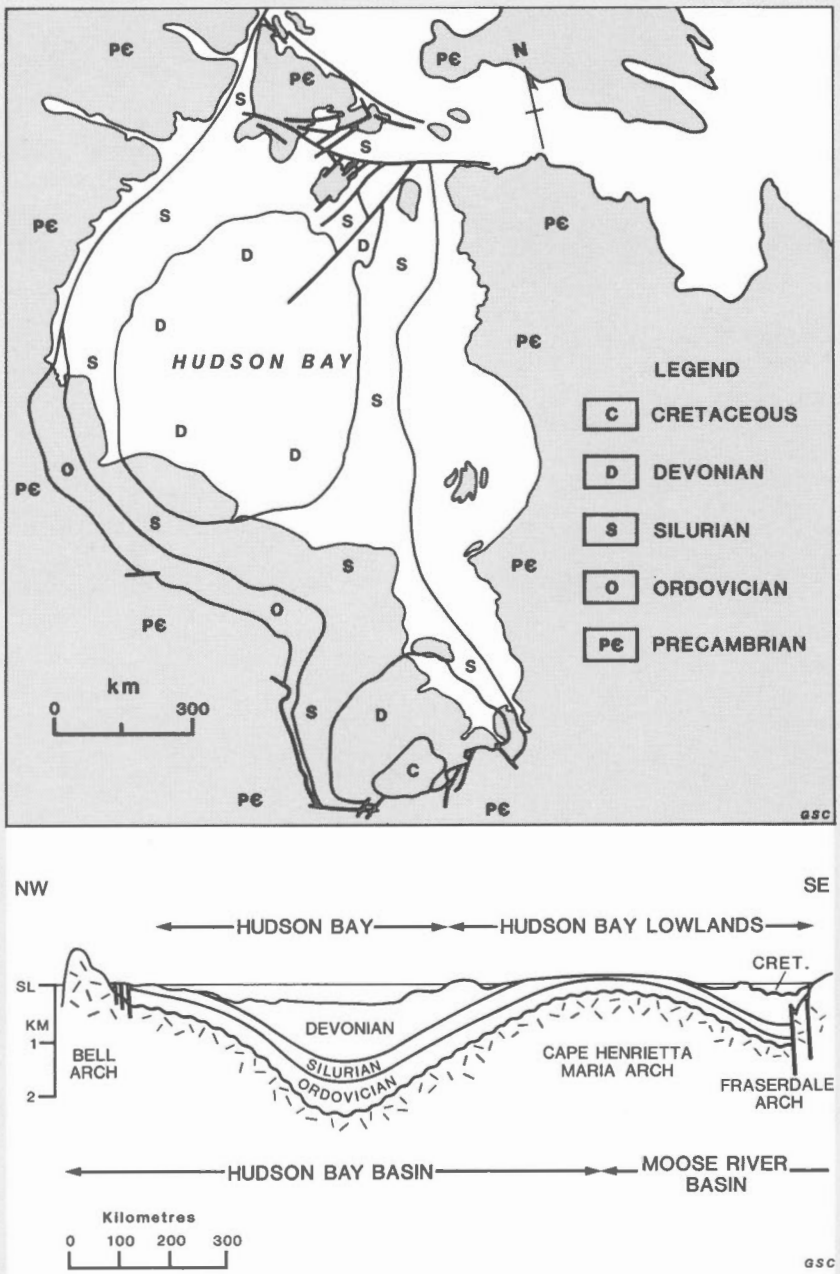


Figure 3.59 Geological map of Hudson Bay-James Bay with structure section (Sandford and Norris 1973)

MARITIMES BASINS

Area Approximately 225 000 square kilometres of which about one third is onshore.

Geology This area includes three major elements; the Magdalen Basin with up to nine kilometres of upper Devonian to Permian sediments; the Fundy Basin with more than six kilometres of probable Carboniferous to lowermost Jurassic sediments; and the Sydney Basin with up to five kilometres of Carboniferous rocks, Figure 3.61. The oldest formations are largely coarse to fine-grained, red continental clastics succeeded by evaporites and some limestone beds, all of Early Carboniferous. These are overlain by thick continental red and grey sandstone-shale sequences of Late Carboniferous age and locally thin Permian red beds. A thick wedge of upper Triassic — lowermost Jurassic continental red beds unconformably overlies the Paleozoic rocks in the Fundy Basin, Figure 3.60.

Drilling History Reliable statistics on early oil and gas exploratory drilling in these areas are not readily available. Between 1970 and 1980, nine wells were drilled in the offshore areas of these basins, six in Magdalen Basin, two in the Sydney Basin and one in the Fundy Basin.

Potential Source Rocks The formations in these areas are almost entirely continental and contain mostly terrestial organic matter. Also many of the sequences are thermally over-mature indicating gas as the most likely hydrocarbon. An exception is a local occurrence of Early Carboniferous petroliferous lacustrine beds which have generated gas, oil, and the solid bitumen Albertite.

Potential Reservoir Rocks Formations in these basins are dominated by continental sand and shale sequences which contain good reservoir beds with the intervening shales providing seals.

Known and Potential Hydrocarbon Occurrences The small oil and gas field at Stony Creek New Brunswick, was discovered in 1909. In 1974, an exploratory well, East Point, in the Gulf of St. Lawrence tested a small gas accumulation in a Late Carboniferous sandstone reservoir over a large salt structure. Two wells drilled in the Sydney Basin in 1974 and 1976 encountered very minor gas shows in a basal conglomerate. Plays in all these basins will be associated with a variety of basement and salt structures, and stratigraphic traps.

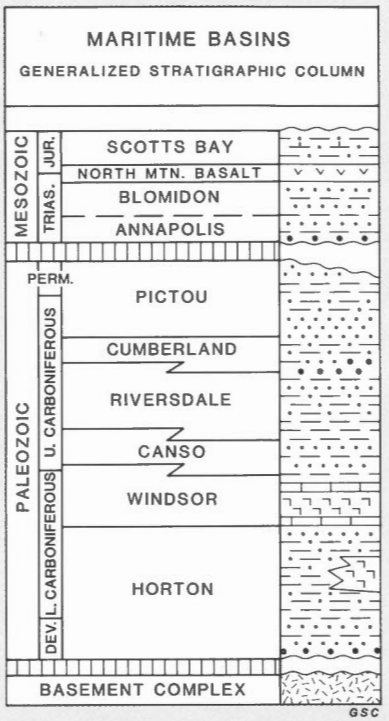


Figure 3.60 Maritimes Basin

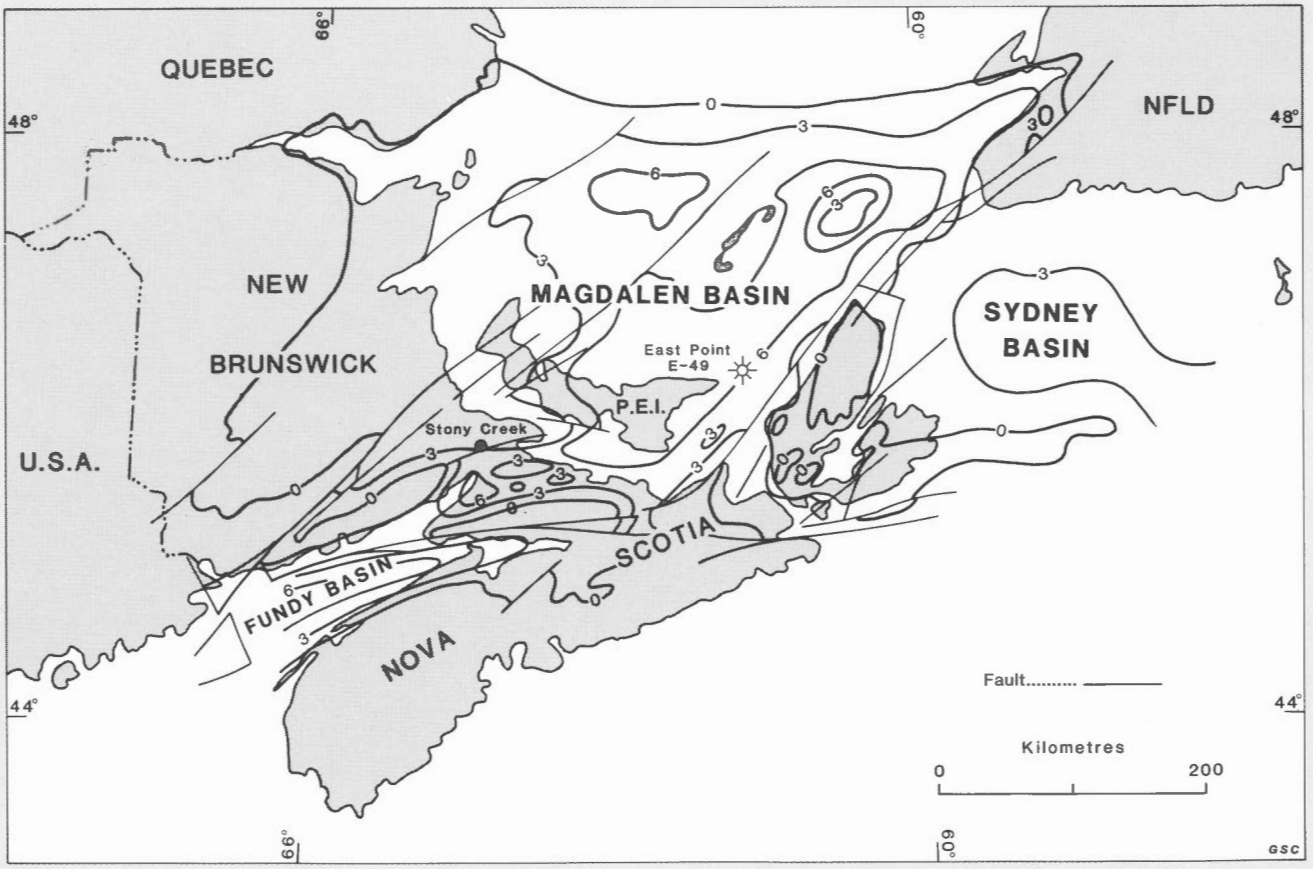


Figure 3.61 Sediment fill map of Maritimes Basins. Contours in kilometres

NON-CONVENTIONAL RESOURCES

FEATURES

NON-CONVENTIONAL RESOURCES

Introduction

In addition to Canada's conventional oil and gas resources, major accumulations exist in a non-conventional category. These include oil sands, heavy oil, carbonate oil, "Deep Basin" gas, and oil shale. These resources are termed nonconventional in that they cannot be produced effectively by normal oilfield techniques. These resources are commonly viewed as potential oil and gas but differ from other potential resources in that they have been discovered. Their extent, location and quantity are well defined and the major impediment to their development is the cost of extraction, and development of new technology to reduce those costs.

Oil Sands

Canada's largest and best known oil sands occur in Lower Cretaceous sandstones in Alberta. Although commonly called the Athabasca oil sands, they occur in several separate deposits (Figure 4.1) with a common geological setting. Sandstones and shales of the Lower Cretaceous (Mannville Group) were derived from both the shield area to the east and from orogenic activity in the west. The sands were transported to the Alberta Basin by a series of rivers and deposited in a complex of fluvial-deltaic nonmarine to marine environments. Extensive oil generation, migration and trapping has formed the oil sands which are among the largest oil accumulations in the world. The oil in these sands occurs as bitumen and behaves essentially as a solid unless heated. About 10% of the total deposits crops out at the surface and methods of open-pit mining have been developed. The remainder occurs at depths to 1 000 metres. These latter deposits will probably be developed by in-situ processes using steam and other techniques similar to those of enhanced oil recovery.

Quantities of in-place crude bitumen contained in the oil sands according to the Energy Resources Conservation Board of Alberta are:

	($10^6 m^3$)
Athabasca	152 640
Buffalo Head Hills	920
Cold Lake	32 590
Peace River	11 440
TOTAL	197 590

To date, the two operating mines, Suncor and Syncrude, have processed 65 million cubic metres of crude bitumen which after refining amounts to production of 46 million cubic metres. Established remaining reserves of synthetic crude oil are currently listed as 3 860 million cubic metres.

Oil sands are also known to exist in Triassic sandstones on Melville Island. The deposit is considerably smaller than those in Alberta but probably contains more than 500 million cubic metres of bitumen in-place.

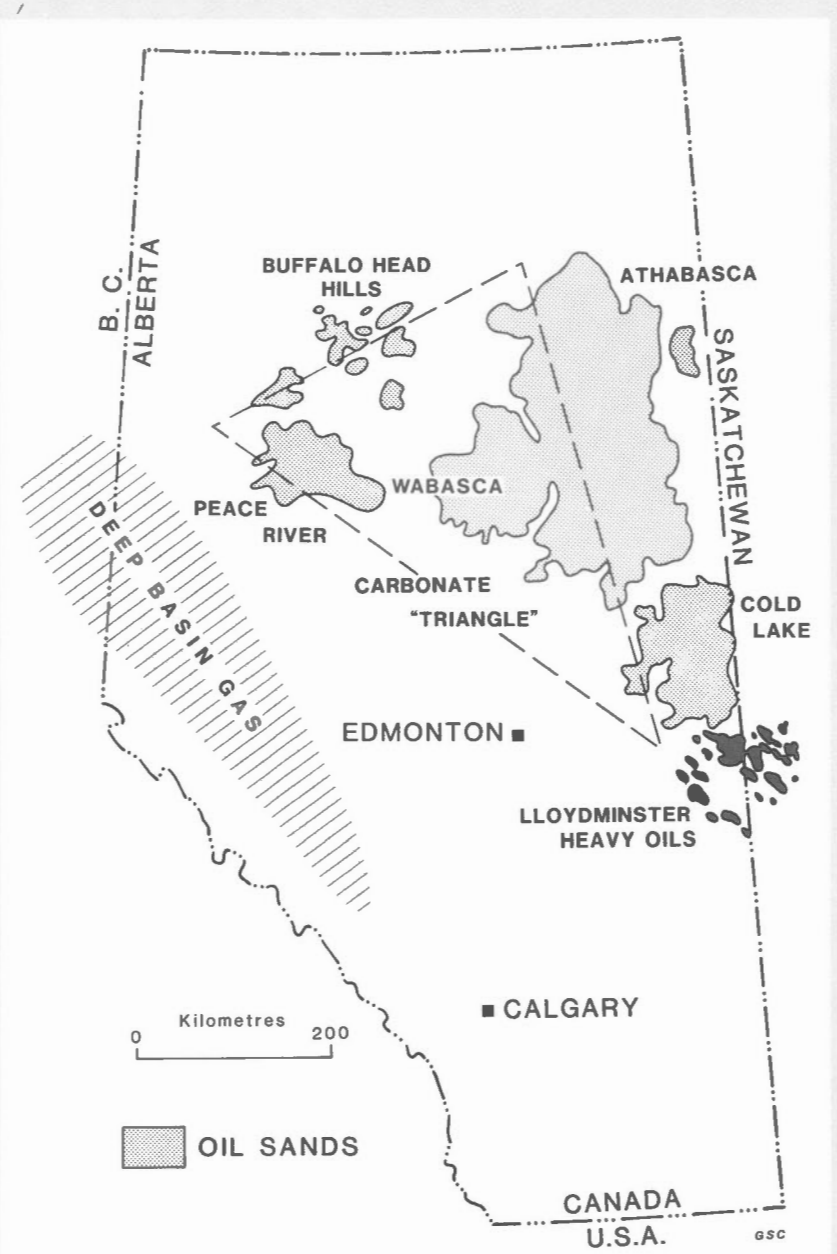


Figure 4.1 Index map. Location of oil sands, deep basin gas, heavy oil, and carbonate oil

Heavy Oil

Deposits of heavy oil in the Lloydminster area are included here as non-conventional even though they have a small component that can be produced conventionally. However, the total percentage of the resource likely to be recovered conventionally is small, and significant future production will have to rely on non-conventional techniques. The heavy oil deposits occur in the same geological setting as the oil sands except that the depositional environment has been dominantly fluvial-intertidal, resulting in a series of thin discontinuous cyclic sand-shale sequences. Individual sandstone beds contain net-pay in the five to ten metre range on average, and occur at depths of about 1000 metres. The gravity of the Lloydminster type oils is higher than in the nearby Cold Lake oil sands and varies from 13° to 18° API.

Total heavy oil in-place, based on extensive geologic analysis, is estimated to be 5 200-7 460-10 630 million cubic metres for high confidence — average expectation and speculative estimates respectively. If the total reserve is restricted to "rich" oil, (thicker beds, high oil saturation, no underlying water, etc.), these values reduce to 2 380-3 010 and 3 650 million cubic metres. The resource is divided almost equally between Alberta and Saskatchewan, and is being actively examined in many fields for application of enhanced recovery methods. Estimates of the total percentage of the resource which will be recoverable are highly cost-price dependent and are not included in this report.

Carbonate Oil

Crude bitumen accumulations are known to exist in carbonate rocks of Devonian and Carboniferous age that subcrop beneath the Alberta oil sands (Figure 4.2). Early estimates of total bitumen in-place were of the same magnitude as that of the oil sands, but very little is known about most of the accumulations in what has been termed the "carbonate triangle" (Figure 4.1). One unit, the Grosmont Formation, is considered to contain the most crude bitumen and has the best reservoir properties for potential development. The Energy Resources Conservation Board of Alberta has designated in-place crude bitumen reserves of 50 million cubic metres to the Grosmont Formation as of December, 1981. The Grosmont accumulations occur at depths of 200 to 500 metres and development will have to rely on in-situ recovery processes.

Deep Basin Gas

Gas resources in quantities as large as Canada's existing reserves are said to exist in the "Deep Basin" of western Alberta and adjacent British Columbia (Figure 4.1). These so-called "tight gas" resources are non-conventional in the sense that they exist down-dip from regional water, and in rocks of very low porosity with ultra low permeability (Figure 4.3). Large scale exploitation of these resources would also be non-conventional, dependent on massive hydraulic fracturing of the section to enable effective drainage. Some of the deep basin gas is in connection with conventional sandstone and conglomerate reservoirs, as in the Falher sands of Cretaceous age in the Elmworth gas field. At Elmworth, some ten billion cubic metres of "tight gas" are considered to be in contact with conglomerates and assigned as reserves. The Geological Survey of Canada has not yet evaluated deep basin "tight gas" potential, which occurs from Permian through Cretaceous units, but industry estimates as high as 8 500 billion cubic metres of gas have been published.

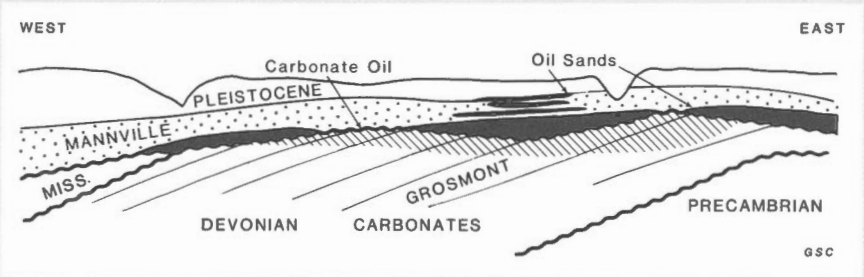


Figure 4.2 Schematic section illustrating trapping of bitumen in oil sands and carbonates

Oil Shale

Canada's oil shale deposits are widely distributed across the country and occur in rocks from Ordovician to Cretaceous age (Figure 4.4). Oil shales actually include a variety of fine-grained sedimentary rocks containing indigenous organic matter that is mostly insoluble in petroleum solvents, and from which shale oil can be extracted by pyrolysis. The organic matter is usually kerogen, an insoluble solid organic material, and lesser amounts of bitumen. The organic material has been derived primarily from algae and spores incorporated into fine-grained sediments.

Carboniferous oil shales of the Albert Formation in New Brunswick are the best known and delineated of Canada's deposits. These deposits are similar lithologically to the famous Green River Shales of Colorado, which are considered economically exploitable. The New Brunswick deposits occur from surface to 615 metres depth. Some intervals contain more than 100 litres of shale oil per tonne of rock. Published reserves are estimated as in

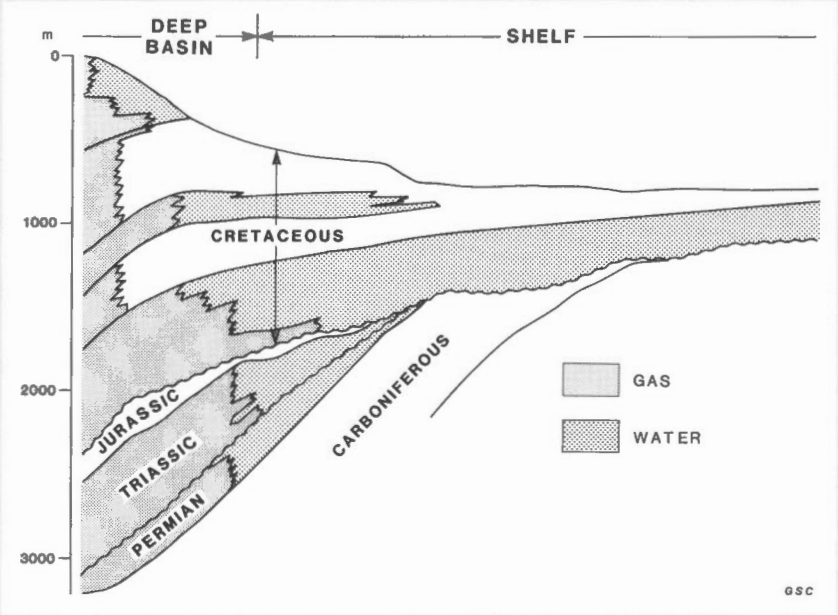


Figure 4.3 Schematic section of tight gas trapped by permeability barriers below water zone

excess of 45 million cubic metres in-place. Except for the New Brunswick deposits, there is insufficient data upon which to base estimates of potential resources.

Economic and Environmental Considerations

Oil Sands The oil sands of Alberta potentially represent energy supplies having no exploration cost. The cost of recovering these resources is a function of the thickness of overburden and/or depth of deposits as well as their pay thickness and quality. Economic evaluation reveals an encouraging comparison of the investment cost per cubic metre (capital investment per cubic metre of recoverable reserves) for these bitumen projects when compared to the development of frontier oil discoveries. Current estimates show that surface mining and in-situ bitumen projects have an investment cost ranging from $20 - $45 per cubic metre of recoverable reserves in 1983 dollars. This compares to $25 - $35 per cubic metre for East Coast development in water depths of less than 100 metres and $40 - $60 per cubic metre for shallow Beaufort Sea developments. However, it must be noted that operating costs for oil sands projects are higher than those for conventional oil operations. Surface mining of oil sands leaves substantial residuals as solid wastes including overburden, and air and water pollutants. Environmental residuals are generally lower for in-situ operations. However, the processing facilities for in-situ operations could contribute to air and water pollution. Mitigation of these undesirable pollutants imposes additional costs.

Deep Basin Gas Tight formation gas is produced from reservoirs with an average permeability of less than 1 millidarcy. Additional costs are incurred in formation fracturing to increase productivity and because of the depths to which these wells are drilled. The gas, however, is sweet and does not require complex processing, and also is accessible to pipeline. No particular environmental hazards are posed.

Oil Shale Costs of oil shale development depend largely on the extraction process. Oil shale can be mined and then processed on the surface, or it can be processed underground (in-situ) and the resulting liquids withdrawn by wells. The drilling, blasting, and excavation technologies applicable to surface coal mining also apply to surface oil shale mining, except that oil shale zones can be very thick and considerably harder than coal seams. The in-situ approach involves fracturing the oil shale underground, introducing heat to cause pyrolysis underground, and collecting and withdrawing the shale oil, through wells, to the surface for upgrading. Upgrading is accomplished by reducing the viscosity, sulphur and nitrogen content of the shale oil. The primary tradeoff in transportation will be between the added cost of transportation of the oil prior to upgrading versus the cost of decentralized refining at each retorting site.

With regard to environmental concerns, surface mining of oil shale leaves many residual air and water pollutants, solid wastes plus overburden, and results in land consumption and reclamation. Environmental residuals are generally lower in underground mines and for in-situ operations than in surface mines, particularly for solid wastes. However, the necessary upgrading or processing facilities would have added costs due to air and water pollution controls and the handling of hot oil production.

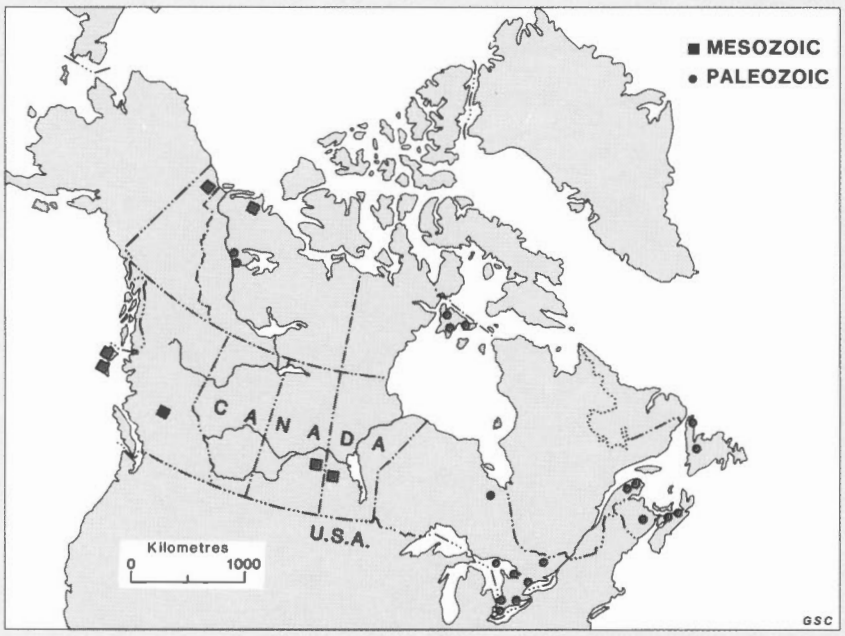


Figure 4.4 Index map of oil shale occurrences in Canada

ESTIMATES OF CANADA'S RESOURCES

FEATURES

RESERVES

TABLE XII
REMAINING RESERVES AND DISCOVERED RESOURCES OF CANADA
(Recoverable)

	OIL ($10^6 m^3$)	GAS ($10^9 m^3$)
WESTERN CANADA SEDIMENTARY BASIN	754	2111
BEAUFORT SEA-MACKENZIE DELTA	115*	283*
ARCTIC ISLANDS	76*	360*
EASTERN CANADA-OFFSHORE	273*	242*
PALEOZOIC BASINS-EASTERN CANADA	1*	9*
TOTAL	1219	3005

* Best current estimate of discovered resources

Conventional Oil and Gas Reserves

The most recent estimates of remaining established reserves prepared by the National Energy Board (NEB) as of year end 1981 are indicated in Table XII for the Western Canada Sedimentary Basin. These values have been adjusted modestly to incorporate slight differences in reserves in the District of Mackenzie estimates provided by the Resource Evaluation Branch, a unit of the Canada Oil and Gas Lands Administration (COGLA). Best current estimates of discovered resources in the frontier regions were supplied by COGLA and are indicated in Table XII. Estimates of reserves shown for the Paleozoic Basins of Eastern Canada (all in Southern Ontario) are from the Canadian Petroleum Association.

The distinction between established reserves and best current estimates of discoveries cannot be overemphasized. The established reserves can be viewed as rigorously quantified amounts of oil and gas that can be produced with identified economics with high certainty. The best current estimates, on the other hand, are commonly based on a single well per discovery plus best available geological-engineering judgement. Such estimates are subject to major revision. The economic viability of discovered resources in frontier basins is at this time uncertain. The inclusion of both types of reserves in Table XII is for convenience of comparison and does not imply equality of confidence in the estimates.

The tabulation of reserves indicates that although important discoveries have been made in each of the frontier regions, the bulk of discovered resources exist in the Western Canada Sedimentary Basin. This is particularly true for gas reserves which have grown significantly since the last report, EP 77-1. Oil reserves of Western Canada have declined from 1175 million cubic metres reported in EP 77-1; this decline being slightly less than the amounts discovered in frontier regions in the same time period.

Non-Conventional Oil and Gas Reserves

All of the resources indicated in the chapter on Non-Conventional Resources could be counted as reserves in the sense that they have been discovered and their distribution is known with some high level of confidence. However, because the quantities that can ultimately be produced from these resources is totally dependent on as yet uncertain costs and future technology, only a small amount can be considered equivalent to the reserves indicated in Table XII. The established remaining reserve estimate of synthetic crude oil of 3 860 million cubic metres as of year-end 1981 (Energy Resources Conservation Board of Alberta) represents reserves of oil sands in the mining area known to be economically viable at this time.

Enhanced Oil Recovery

A category of oil potential that has not been discussed elsewhere in this report is additional oil that may be recovered from existing and potential oil pools by the introduction of enhanced oil recovery techniques. These techniques include a wide variety of processes, many of them experimental, designed to recover oil left behind in the reservoir after primary and secondary (waterflood) production. Methods include the introduction of chemicals, steam stimulation and floods, carbon dioxide floods, and wet and dry thermal stimulation.

Introduction of enhanced recovery methods usually requires very detailed reservoir characterization, computer modelling of the proposed process and small scale (pilot) field trial before actual field development. The final field application usually involves much closer well spacing than that used in primary-secondary recovery. The total process from design to first production may take five to ten years. All of these considerations contribute to the difficulty of predicting potential quantities of oil that will result from enhanced recovery. The Geological Survey's current estimate of enhanced oil recovery potential from Western Canada was prepared in 1978 and suggests a range of 160-500-950 million cubic metres of potential for high confidence, average expectation and speculative values respectively.

POTENTIAL

Table XIII
OIL AND GAS POTENTIAL OF CANADA
(Recoverable)

OIL POTENTIAL ($10^6 m^3$)	High Confidence	Average Expectation	Speculative Estimate
WESTERN CANADA SEDIMENTARY BASIN	234	593	1210
CORDILLERAN BASINS	—	50	110
BEAUFORT SEA-MACKENZIE DELTA	307	1464	2962
ARCTIC ISLANDS	316	686	1305
EASTERN CANADA OFFSHORE	512	1877	3392
PALEOZOIC BASINS-EASTERN CANADA	20	167	605
TOTAL	1486	4827	8995

GAS POTENTIAL ($10^9 m^3$)	High Confidence	Average Expectation	Speculative Estimate
WESTERN CANADA SEDIMENTARY BASIN	1544	2504	4930
CORDILLERAN BASINS	40	270	760
BEAUFORT SEA-MACKENZIE DELTA	871	2151	4103
ARCTIC ISLANDS	1100	2257	3662
EASTERN CANADA OFFSHORE	725	2423	4613
PALEOZOIC BASINS-EASTERN CANADA	46	190	660
TOTAL	4342	9795	18285

Conventional Resources

Quantities of oil and gas estimated to exist in the six petroleum regions of Canada are listed in Table XIII. The values of estimates are indicated as recoverable in the sense of technically recoverable with neither economic constraints nor concern of whether and when the resources may be discovered. Accordingly, the reader is cautioned that potential resources are undiscovered and must not be regarded with the same confidence as estimates of reserves.

Oil potential is estimated to be greatest in the Eastern Canada Offshore Region at both average and speculative values. Expectations are strongly focussed at the region surrounding the giant Hibernia discovery and in small basins to the east. The Beaufort Sea-Mackenzie Delta region ranks second in terms of oil potential, with numerous discoveries already made but as yet poorly defined. The largest remaining potential is expected to occur in intermediate to deep water parts of the Beaufort Sea. The oil potential described for Western Canada will probably occur in much smaller fields than those in the frontiers, but will have the advantage of economic viability and relative ease of exploration.

Gas potential is estimated to be more-or-less equal for each of the frontier regions and the Western Canada Sedimentary Basin, particularly at the average expectation level of confidence. Giant or near giant-sized discoveries have already been made in each of the frontier regions and additional large-sized discoveries can be confidently predicted. The logistical difficulties of development, and consequent costs will ultimately determine which of the regions will contribute most to future supply. The tendency in Western Canada will be for somewhat smaller discoveries, but major fields are estimated to exist albeit with lesser confidence.

Non-Conventional Resources

Quantities of non-conventional resources estimated to exist in Canada dwarf those of the conventional category. They qualify as potential in that their inclusion with established recoverable reserves would certainly present a distorted view. The very large in-place resource estimates have limited meaning until they can be described in an economic context. Of the several categories of non-conventional resources described earlier, the greatest promise for future potential lies in the oil sands and heavy oil deposits. Several additional open-pit mining operations of the same magnitude as the existing two could be developed. Smaller scale in-situ development in the Cold Lake deposit is equally promising and could contribute significant production. Extensive development of the Lloydminster-type heavy oils represents a much smaller scaled series of operations. All of these options are highly sensitive to cost and price consideration.

CONCLUSIONS

Conventional Resources

Canada's potential oil and natural gas resources are large and could ensure self-sufficiency if means can be found to convert a significant portion of them into economic reserves. The potential for future discovery is greater in the frontier regions than in western Canada. This is due to the degree of exploration maturity of the Western Canada Sedimentary Basin.

The portion of these resources that is, or will be, commercially viable depends on prevailing economic conditions as affected by technological progress in development, production and transportation. To date there has been no consensus regarding specific development, production and transportation systems suitable for frontier discoveries, particulary for offshore areas. This has hampered the ability to estimate the contribution that frontier resources can make to future Canadian energy supplies. The Department is working towards providing estimates that can be used with a reasonable degree of confidence.

The pace of exploration, and therefore the rate at which frontier resources are discovered, will be affected by factors that include exploration success; expectations regarding market prices, development and operating costs; prevailing fiscal regimes; technological progress; and successful commercial exploitation of discoveries already made. Lead times from discovery to commercial development are long in frontier regions and it is unlikely that large-volume frontier production will be available to Canadian markets until the 1990's.

For the balance of this decade therefore, domestic oil supply will have to depend primarily on western Canada reserves. Infrastructure already in place in this area ensures that newly-found conventional reserves can be quickly placed on production, however more intensive exploration efforts will be needed to accelerate discovery. Enhanced recovery of existing light and medium crude oil reserves and of heavy crude oil can, as well, make a substantial contribution to supply over this period.

Oil supply beyond 1990 will likely include production from frontier discoveries in the East Newfoundland Shelf, Arctic and the Beaufort Sea regions. Given the appropriate economic climate, additional in-situ oil sands projects, surface mining oil sands plants, heavy oil and an increasing quantity of enhanced recovery supply can also be viewed within this time-frame, as well as a continuing contribution from conventional oil from the Western Canada Basin.

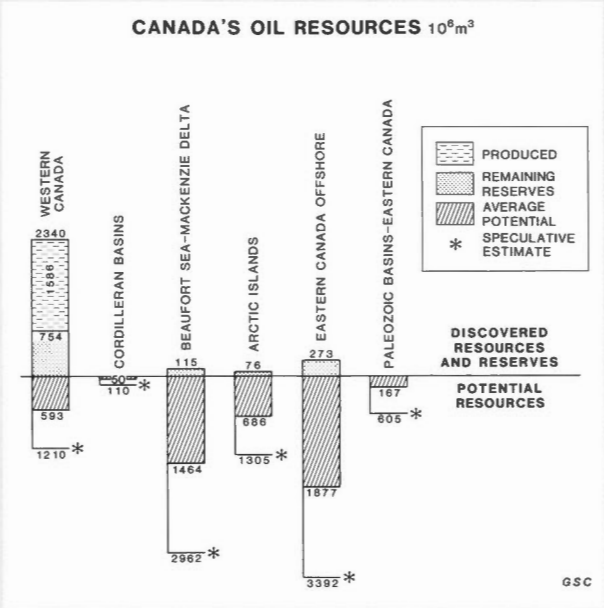


Figure 6.1 Bar chart, Conventional Oil Resources of Canada

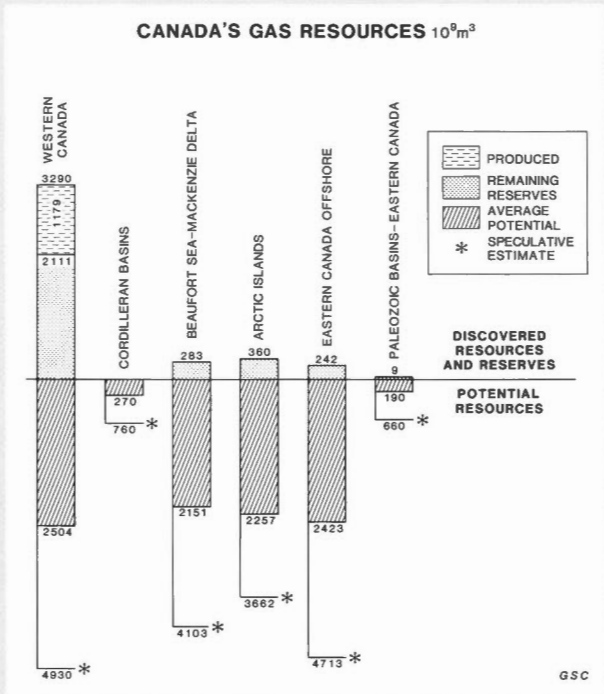


Figure 6.2 Bar chart, Conventional Gas Resources of Canada

In addition to development of oil deposits already taking place in the Mackenzie Corridor, pipeline access to the northern frontiers would open other oil resources of the Mackenzie Corridor to southern markets.

Gas potential estimated in all frontiers plus western Canada, in addition to present reserves, indicates an assured supply. These resources should meet current requirements as well as expansions of Canadian gas markets for the foreseeable future. This will, of course, require development investments to maintain and expand delivery capacity from western Canada.

Major current limitations on frontier gas development are high development, operating and transportation costs, and lack of markets. In addition, remote frontier projects face technological and environmental hurdles.

Non-Conventional Oil Resources

The future mix of non-conventional and conventional resources in supplying domestic energy requirements will depend on the relative costs of exploration, development, operation and delivery to market.

Canada has a large potential supply of oil from heavy oil reservoirs and oil sands deposits. These resources represent a known source of supply, probably exceeding conventional oil resources in terms of quantity ultimately producible. Available upgrading technology together with development and operating costs are the limiting factors in bringing these supplies to the Canadian market. Although the technology for heavy oil and bitumen extraction exists at this time, a full realization of the potential from in-situ recovery and heavy oils will require advances in upgrading technology. Small scale upgrading projects could allow technology demonstration and improvements and hopefully will lead to larger scale projects.

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