

PETROLEUM EXPLORATION IN NORTHERN CANADA
A Guide to Oil and Gas Exploration and Potential

Northern Oil and Gas Directorate
Indian and Northern Affairs Canada

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PREFACE

Petroleum Exploration in Northern Canada has been published to mark the reopening of vast regions of the North to new exploration rights issuance, the first in 25 years in the mainland Northwest Territories.

Oil and gas activity on lands north of 60° under federal jurisdiction has a long history, extending back to the discovery of the Norman Wells Oil Field in 1919. Exploration rights issued throughout the 1960s and 1970s covered almost all of the prospective sedimentary basins in the North.

In the 1970s, the government instituted a freeze on the issuance of new exploration rights in order to facilitate the Aboriginal land claims process in general, and the accompanying land selection process in particular. At the time, it was not anticipated that the land claims process would take so long to conclude; two decades passed before the signing of recent land claim settlements. In the intervening years, almost all historical exploration rights have lapsed.

The rights issuance process was re-introduced after the settlement of land claims in the Beaufort-Mackenzie Basin in 1989, in the High Arctic in 1991, and in the mainland Northwest Territories in 1994. The significant response to the recent renewal of issuance of exploration rights in the mainland territories may, in fact, signal a new cycle of petroleum exploration in the North.

The hiatus in rights issuance and hence in oil and gas activity has, no doubt, created a similar hiatus in companies' knowledge of the petroleum potential of the North. This publication offers both a quick look at the majority of potential petroleum-bearing basins, and a more comprehensive summary of the petroleum geology, exploration history and oil and gas potential of each basin. It provides potential explorers with a handy reference to acquaint themselves with the significant potential the North has to offer.

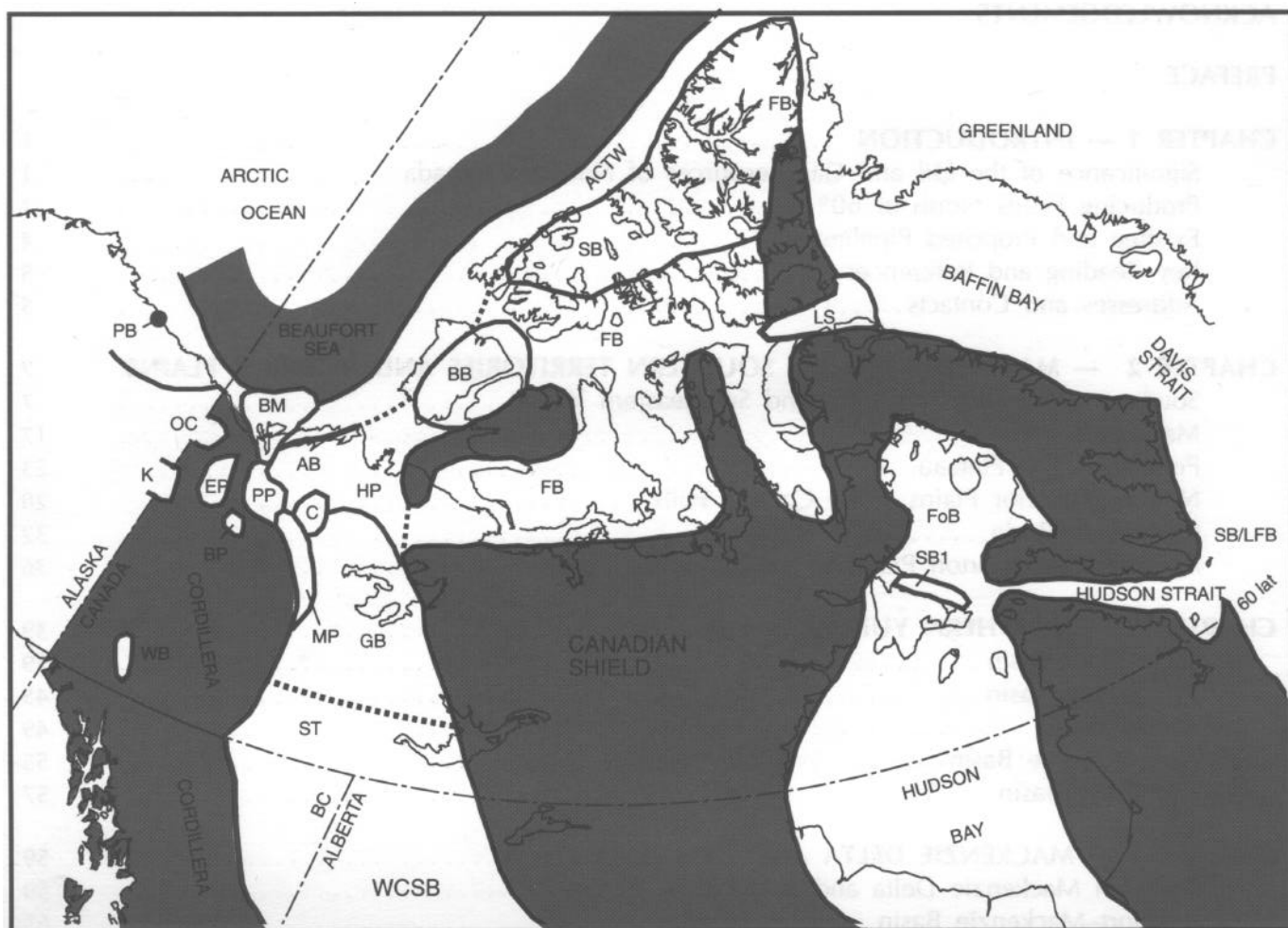
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WCSB	Western Canada Sedimentary Basin	PP	Peel Plateau/Peel Plain	BM	Beaufort-Mackenzie Basin	ACTW	Arctic Continental Terrace Wedge
ST	Southern Territories	C	Colville Hills	AB	Anderson Basin	LS	Lancaster Sound Basin
GB	Great Bear Basin	BP	Bonnet Plume Basin	HP	Horton Plain	SB/LFB	Saglek and Lady Franklin basins
WB	Whitehorse Basin	EP	Eagle Plain Basin	BB	Banks Basin	FoB	Foxe basin
MP	Mackenzie Plain	K	Kandik Basin	FB	Franklinian Basin	SB1	Southampton Basin
		OC	Old Crow Basin	SB	Sverdrup Basin	PB	Prudhoe Bay

Figure 1. Sedimentary basins of northern Canada.

CHAPTER 1 — INTRODUCTION

Canada north of 60° latitude largely comprises two territorial jurisdictions – the Northwest Territories and Yukon. The surface area of the territorial lands amounts to approximately 40% of the entire land surface of Canada. A further vast area is covered by shallow seas along the continental shelves of the Arctic and North Atlantic oceans and within the Arctic archipelago. Fifty per cent of this region is underlain by sedimentary rocks and the remainder by metamorphic and igneous rocks of the Canadian Shield.

This publication is a reference for those interested in the oil and gas resources of northern Canada. Key geographic information, a summary of petroleum geology, exploration history, and oil and gas potential for each basin appear in the following pages. The order of treatment follows a clockwise progression beginning at the Alberta-British Columbia border at 60°N, north to the Beaufort Sea, northwest to the Arctic Islands, east to the shores of Baffin Bay and south to the Hudson Strait.

Geographical boundaries between provinces and territories do not reflect the underlying geology. The Western Canada Sedimentary Basin extends from Alberta and British Columbia into the Northwest Territories and Yukon, and north to the Beaufort Sea. Similarly, the offshore basins of the eastern Arctic mark the northeastern terminus of the North Atlantic rift system. The pattern of exploration, in contrast, has been strongly influenced by geography; thus the density of drilling in the Western Canada Sedimentary Basin south of 60°N is much greater than further north despite comparable geology and significant oil and gas potential. Northern Canada comprises a mosaic of sedimentary provinces each with differing geological history and petroleum potential. Some – the Sverdrup Basin of the Arctic Islands is an example – are unique in North America; others, such as the Tertiary basin of the Mackenzie Delta-Beaufort Sea, have similarities to the Mississippi Delta of the Gulf of Mexico.

This catalog describes 19 exploration regions of northern Canada which in most cases conform to the extent of underlying sedimentary basins (Fig. 1). Our definition of “basin” is deliberately loose and may not conform with a rigorous technical definition. It recognises that structural or geographic discontinuities separating areas with common petroleum geology subdivide the territories into theatres of operation where costs bear a consistent relationship to exploration risk and potential reward. The rigour of treatment of individual basins varies according to

perceived potential: basins with low potential are summarized briefly, with more detailed treatment reserved for basins with high potential.

At the end of each section there is a brief list of key references. This is not intended to be a comprehensive bibliography. The quantity of research in many of these areas is voluminous and those interested are urged to contact the organizations and individuals listed at the end of the introduction.

Significance of the Oil and Gas Resources of Northern Canada

The western provinces of Canada are the principal producing regions of oil and gas in Canada. Eighty-three per cent of gas production and 86% of oil production has come from the province of Alberta alone. However, the principal producing basins are mature and large discoveries are becoming increasingly rare. Remaining established reserves plus discovered resources in the Northwest Territories and Yukon represent 23% of conventional light crude oil and 26% of conventional natural gas remaining in Canada (Figs. 2, 3). Frontier undiscovered potential is much higher at 48% of potential recoverable gas and 59% of potential recoverable oil (National Energy Board, Canadian Energy – Supply and Demand 1993 - 2010, 1994, excluding potential assigned to “other” frontier basins).

The basins of northern Canada contain substantial reserves and a long inventory of discovered resources of both oil and gas. This is one of the last extensive and under-explored hunting grounds for conventional gas and oil remaining in the North American continent. Discoveries made within the next few years can expect to contribute to supply to meet a building continental demand for gas and an increasing share of domestic oil production.

Producing Fields North of 60°

As of 1994, four fields are producing hydrocarbons from the Northwest Territories and Yukon. The Kotaneelee and Pointed Mountain gas fields lie just north of the border with British Columbia at 60°N. These are linked to the Westcoast Energy Inc. pipeline system in British Columbia. Two oil fields are also under production. The largest, Norman Wells, lies at latitude 65°15'N on the Mackenzie River. Oil flows by

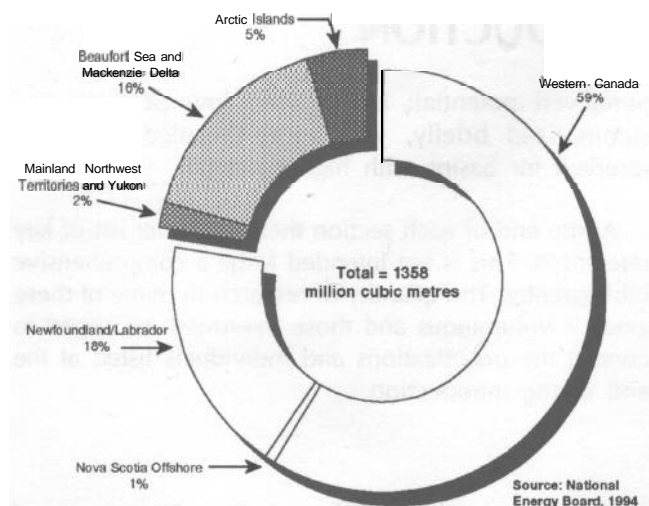


Figure 2. Conventional light crude oil - remaining reserves and other discovered resources in Canada.

pipeline south to Alberta. Bent Horn field on Cameron Island in the Arctic Islands produces from a single well, and oil is transported by tanker to a refinery at Montreal.

The Norman Wells field (Fig. 4)

Most of Imperial Oil Ltd.'s Norman Wells field lies beneath the Mackenzie River southwest of the townsite of Norman Wells. The central processing unit is located on the north bank of the river within the Norman Wells townsite and overlies the northern edge of the field. Originally developed as a producing field during the Canol Project in the 1940s with small volumes of oil exported via the Canol Pipeline to Whitehorse, subsequent production was very limited until the mid-1980s when the construction of the Norman Wells pipeline to Alberta saw a major expansion of field facilities.

Today, 98% of field reserves of $37.3 \times E6 \text{ m}^3$ (235 million barrels) are developed. Reservoir pressure is maintained in 165 production wells by water injection through 156 injector wells across a field-wide five spot pattern. Although most onshore wells in the Norman Wells townsite and on Goose and Bear islands are vertical, the larger proportion of the field has been developed by wells slant-drilled from artificial islands in the Mackenzie River or from along the banks of the river. Future development drilling along the edge of the

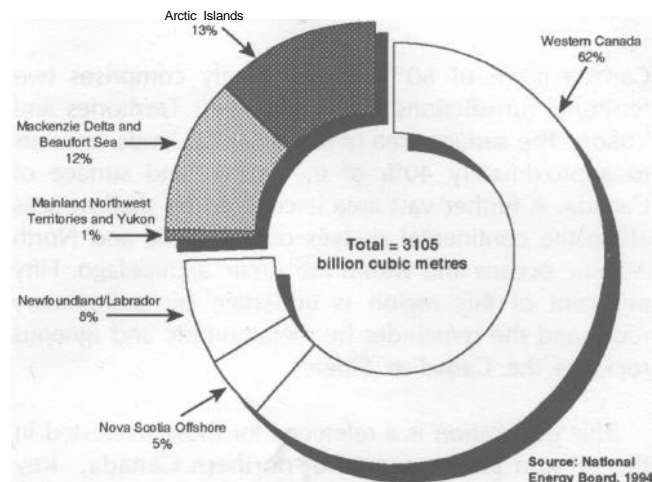


Figure 3. Conventional natural gas - remaining reserves and discovered resources in Canada.

pool will utilize horizontal drilling in a search for greater efficiencies for both production and injection wells.

Production from Norman Wells was $1.79 \times E6 \text{ m}^3$ (11.3 million barrels) in 1993, with cumulative production of approximately $16 \times E6 \text{ m}^3$ (100 million barrels). About 43% of oil in place is expected to be recovered. The operator is actively pursuing schemes to augment recovery and develop reserves peripheral to the field. Together, development drilling and enhanced recovery methods applied to the existing production patterns could sustain the currently high rates of production. However, present indications are that production from the field has started to decline.

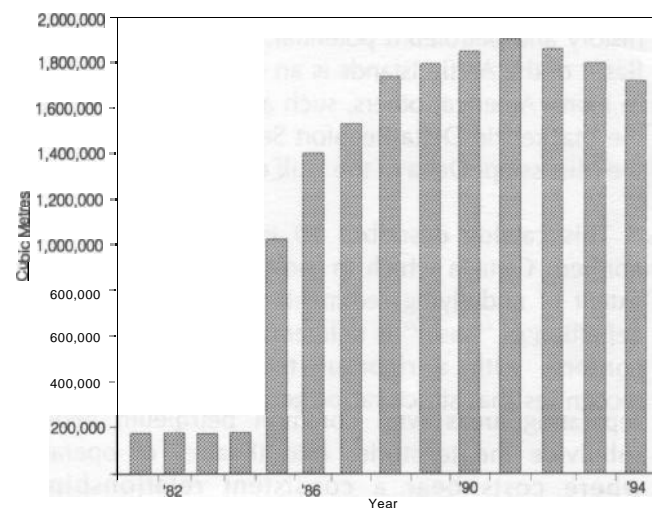


Figure 4. Norman Wells production.

Historical Highlights

Before 1789	Indians make use of petroleum seepages along the Mackenzie River at Bosworth Creek.
1789	Alexander Mackenzie logs "petroleum" seepages from the lower Ramparts during his exploration of the Deh Cho (Great River).
1800's	Dene Indians and Hudson's Bay Co. traders use Fort Good Hope tar springs as their principal source of pitch. In 1860, the Canadian oil industry began with the discovery of oil at Petrolia in southern Ontario.
1887	Emile Petitot notes "Asphalt in great quantities".
Early 1911	A Dene named Karkassee directs the attention of J.K. Cornwall (of the Northern Trading Co.) to "flotsam oil" along the banks of the Mackenzie, leading to the identification of oil seepages at Norman Wells.
1913-1914	Area of seepages at Norman Wells staked by Bosworth - at the same time as the Turner Valley discovery in Alberta.
1919	Imperial Oil buys Norman Wells prospect from J.K. Cornwall.
1920	Northwest Discovery No. 1 flows oil from fractures in the Canol Formation. "Oil comes to surface to black globules . . . trenches fill with oil".
1942	Canol Project. Limited development of the Norman Wells field to fuel the war effort in the Pacific. In the following year, oil began flowing through the Canol pipeline to Whitehorse, Yukon at rates of 3000 barrels per day.
1944	Production reaches 4400 barrels per day but ceases after the war. The pipeline was dismantled in the late 1940's.
Late 1960's	Permitting of frontier lands for exploration results in extensive geophysical exploration and drilling in the Mackenzie Valley and Delta.
1974	The "oil shock" intensifies concern about domestic supply, resulting in the development of incentive programs for frontier exploration and a surge in exploration.
1977	After extensive public consultation with regard to environment and social sensitivities, the Berger Commission recommends that no pipeline be built along the Yukon north shore to Alaska and that a ten year moratorium be placed on pipeline construction in the Mackenzie Valley. Government ceases land disposition until Native land claims are settled.
1975-1985	Exploration drilling intensifies throughout the Canadian frontier and especially in the Mackenzie Delta and Beaufort Sea.
1984	Settlement of Inuvialuit land claim (Western Arctic region).
1986	Norman Wells facilities expand and a pipeline is built to southern markets. Field put on full development for the first time. Fall in oil prices curbs new investment in frontier exploration.
1989	Exploration rights made available in the Mackenzie Delta/Beaufort Sea region for the first time in 20 years.
1992	Settlement of Gwich'in land claim (southern Mackenzie Delta, northern Mackenzie Valley region of the N.W.T.).
1993	Settlement of Sahtu land claim (central Mackenzie Valley, Colville Hills, Great Bear Lake region of the N.W.T.). Signing of land claim with Inuit of Nunavut (eastern Arctic). Signing of Umbrella Agreement with Council of Yukon Indians.
1994	Lands again available for exploration following settlement of Native land claims in mainland N.W.T.

Bent Horn Field (Fig. 5)

Panarctic Oils Ltd.'s Bent Horn field produced 321,469 m³ (2.02 million barrels) of oil in 1993. Oil continues to flow from the single producing well with no indications of declining rate. Production is exported from Cameron Island by a specially reinforced tanker, the M.V Arctic, originally built for operations in the Great Lakes. The tanker makes two and sometimes three trips per year between the field and the Pointe aux Trembles refinery in Montreal.

Kotaneelee Gas Field, Yukon Territory (Fig. 6)

Kotaneelee field lies in the extreme southeastern Yukon, close to the border with British Columbia. After

being suspended for ten years, production resumed in 1991 following the upgrading of gas-handling facilities, workover of one well and re-drilling of a second well. Cumulative production to the end of 1993 was 1271 x E6 m³ (44.9 bcf).

Pointed Mountain Gas field (Fig. 7)

The Pointed Mountain gas field lies in the southwest corner of the Northwest Territories, close to the border of British Columbia and Yukon. The field has been on production since 1972 and is now in the late stages of exploitation. Cumulative production to the end of 1993 was 8.6 x E9 m³ (303 bcf).

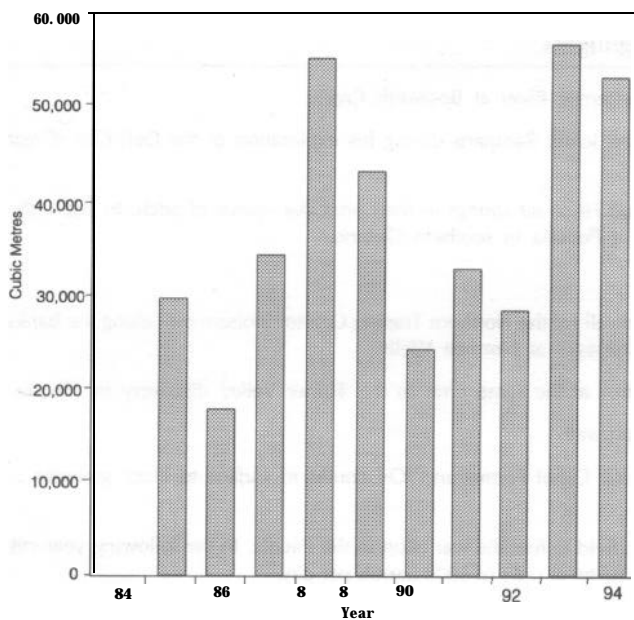


Figure 5. Bent Horn oil production.

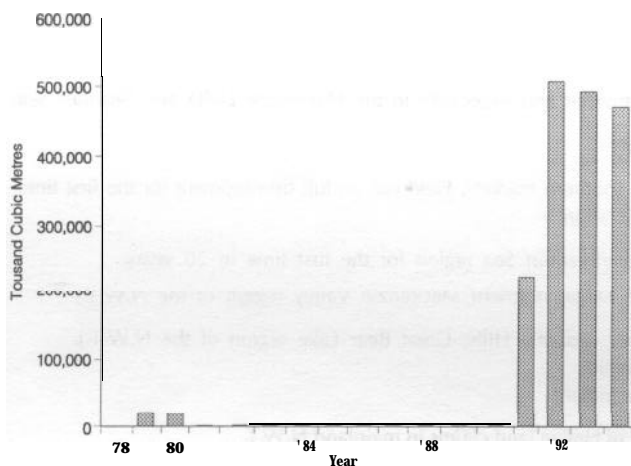


Figure 6. Kotaneelee gas production.

Existing and Proposed Pipelines

Norman Wells oil pipelines

The Canol Project, commenced in 1942, saw limited development of the Norman Wells oil field and the construction of 160 km of 6" pipe and 800 km of 4" pipe to Whitehorse, Yukon Territory. In the following year, oil began flowing through the Canol pipeline to the Whitehorse refinery at rates of 3000 barrels (476 m³) per day. Production reached 4400 barrels (700 m³) per day but ceased after the war. The pipeline was

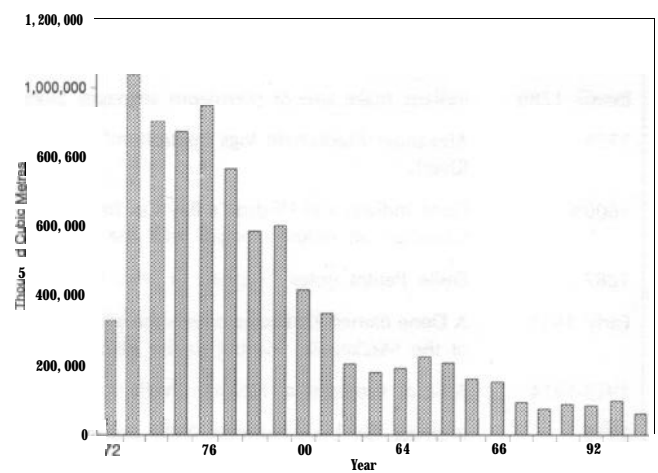


Figure 7. Pointed Mountain gas production.

dismantled in the late 1940s. The products pipeline which ran from Whitehorse to Skagway, Alaska, is now operated by Yukon Pipelines Ltd. to import petroleum products to the Yukon.

The modern Norman Wells pipeline is a 305 mm diameter oil pipeline connecting Imperial Oil's Norman Wells oilfield to Zama (Alberta) 860 km (539 miles) to the south. The pipeline has 3 pumping stations with an average throughput of 4800 m³ (30,000 barrels) per day. Spare capacity exists on this pipeline and throughput could be increased substantially by augmenting compression. Additional spare capacity will also develop over the next decade as production from the field declines.

Existing Gas Pipelines

The Kotaneelee and Pointed Mountain gas fields are already connected to the Westcoast system. Further incremental development of gas pipelines into the southern Northwest Territories and Yukon is occurring in northern British Columbia as fields are progressively tied in. The most recent of these is the 45 km Hossilt pipeline which terminates a few kilometres south of the border with the Northwest Territories.

Proposed Pipelines

The Beaufort Sea contains the largest concentration of gas and oil discoveries in the Canadian frontier with about half the discoveries onshore and the remainder in relatively shallow water in the Beaufort Sea. In 1992, an export licence was awarded by the National Energy Board to a consortium proposing the development of 292.9 x 10¹² m³ (10.339 tcf) of gas reserves in the

Mackenzie Delta. Although the application for a gas pipeline connecting the Mackenzie Delta to southern markets has yet to be made, two general routes have been suggested: one follows the Mackenzie Valley to Norman Wells, thence south to the Alberta border; and a second follows the Dempster Highway into the Yukon to connect with the proposed Alaska Natural Gas Transportation System. Much of the pipeline capacity in northern Alberta and the United States has been "pre-built" in anticipation of this latter project.

A large diameter oil pipeline exploiting the Amauligak field in the Beaufort Sea was suggested when this field was being considered for development in the mid-eighties. Low oil prices caused this project to be indefinitely postponed. A more modest suggestion has been for a smaller diameter oil pipeline connecting the smaller onshore oil discoveries of the delta to Norman Wells. Such a pipeline could exploit developing spare capacity on the Norman Wells to Zama link.

All pipeline development must cope with the great distances and difficult terrain of northern Canada and involves large capital cost. Such ventures require some stability in medium to long term outlook in gas and oil prices. Offshore production directly into tankers is an alternative possibility for offshore Beaufort discoveries. Test production from Amauligak was exported to Japan via Alaska/Beaufort Sea route in the summer of 1986.

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CHAPTER 2 – MACKENZIE VALLEY, SOUTHERN TERRITORIES AND INTERIOR PLAINS

SOUTHERN NORTHWEST TERRITORIES AND SOUTHEASTERN YUKON

Age	Cambrian to Cretaceous
Depth to Target Zone	700 to 4500 m
Maximum Basin Thickness	In excess of 5000 m in foothills belt, shallowing to east
Hydrocarbon Shows	Oil and gas shows in many formations from Devonian to Cretaceous
First Discovery	1955 (Briggs Rabbit Lake No. 1 O-16; Slave Point Gas)
Discovered Resources	Gas: Aggregate in 16 fields: 17.4 x E9 m ³ (615 bcf) Oil: Aggregate oil in 1 field: confidential to date
Production	Gas: 9.5 x E9 m ³ (336 bcf) from Pointed Mountain, Kotaneelee fields Oil: Test production from Cameron Hills
Basin Type	Precambrian rifts; Paleozoic continental margin; Mesozoic foreland basin
Depositional Setting	Paleozoic: shallow marine shelf to shelf margin. Mesozoic: alluvial to shallow-water marine shelf (foreland basin)
Reservoirs	Middle Devonian carbonates (?Upper Devonian carbonates, Mississippian and Cretaceous sandstones)
Regional Structure	Thrust folds in west; normal faulting and possible wrench faulting in the plains
Seals	Thick Devonian shales, some anhydrite, tight carbonates
Source Rocks	Mature Devonian shales, carbonates, evaporites; Mississippian and Cretaceous shales
Depth to Oil/Gas Window	Approximately 800 m
Total Number of Wells	400 (386 exploratory, 14 delineation)
Average Well Density	1 per 464 km ²
Seismic Coverage	7228 km since 1974; from 60-61°N data coverage is good but sparse farther north
Pipelines	Norman Wells oil pipeline to Zama. Point Mountain/Kotaneelee gas pipeline to Westcoast Transmission System in B.C. Gas pipelines to Hossitl and July Lake fields are within a few kilometres of the border with the Northwest Territories
Area	180,000 km ²
Area under Licence (km²)	1100 km ² held by Significant Discovery Licences or leases

(Exploration conditions are comparable to northern Alberta and to the foothills of British Columbia. There is a railhead at Hay River on Great Slave Lake and population/service centres at Fort Liard, Fort Simpson and the territorial capital at Yellowknife.)

This northern extension of the prolific Western Canada Sedimentary Basin shares several prospective exploration plays with northern Alberta and northeastern British Columbia. The Liard Plateau in southeastern Yukon and southwestern Northwest Territories is a gas producing region already connected to the Westcoast pipeline system. Exploration drilling targeted at the numerous untested fault slices in the large thrust-faulted structures of the Liard Plateau (foothills), will undoubtedly add to the stock of gas in the region. Farther east, on the plains, gas has been discovered in 17 exploratory wells and gas shows in 20 other wells. This indicates potential for a density of gas discoveries comparable to adjacent areas of British Columbia and Alberta. Recently, test production of oil from Cameron Hills has vindicated regional geochemical studies which indicated oil potential in the shallower eastern part of the region north of the Alberta border.

Geological Setting (Figs. 8, 9)

The late Precambrian saw the opening of the proto-Pacific along the length of the North American craton. Extensional tectonics during this period created a horst and graben fabric in the Precambrian basement across which sediments of the evolving passive margin of western North America were subsequently deposited. The basement fabric has since had a major influence on depositional patterns and structural development of the region.

The southern Northwest Territories and southeastern Yukon overlie a cross-section of the Paleozoic continental margin. Evaporitic and clastic sediments were deposited in a proximal setting fringing the Canadian Shield, while shelf carbonates and shales were deposited in a distal setting along the outer rim of the carbonate platform.

Early Cambrian deposition was predominantly clastic, with quartz-rich sandstones filling valleys and thinning onto the flanks of hills on the deeply eroded Precambrian surface. Cambrian sediments appear to have been largely removed or were not deposited across much of the southern Territories save in the deep rift of the Root Basin in the west of the area.

Clastic deposition was superseded by shelf and bank carbonate deposition which was more or less continuous from the Middle Cambrian to the Middle Devonian. The Tathlina High - an east-west topographic high lasting until the Late Devonian - fixed the northern margin of Middle Devonian (Givetian) carbonate deposition. The thick reefs localized above the Tathlina High constitute the Presqu'île Barrier. North of the Presqu'île Barrier, water depths increased into the Horn River basin where shale deposition predominated. Towards the end of the Devonian a widespread shale basin with intermittent carbonate deposition developed, which persisted through the Mississippian.

Uplift of the Cordillera began in the Early Cretaceous. Folding and thrusting of the thick Paleozoic sequence created the foothills belt in the western part of the region and transformed the Paleozoic oceanic margin into the continental seaway, which characterized the Mesozoic. Subsequent deposition was in a foreland basin setting.

The eastern limits of the disturbed belt are known only approximately: south of 61°N the northward strike of the Bovie Lake structure provides a convenient limit but orogenic influence has certainly extended east of

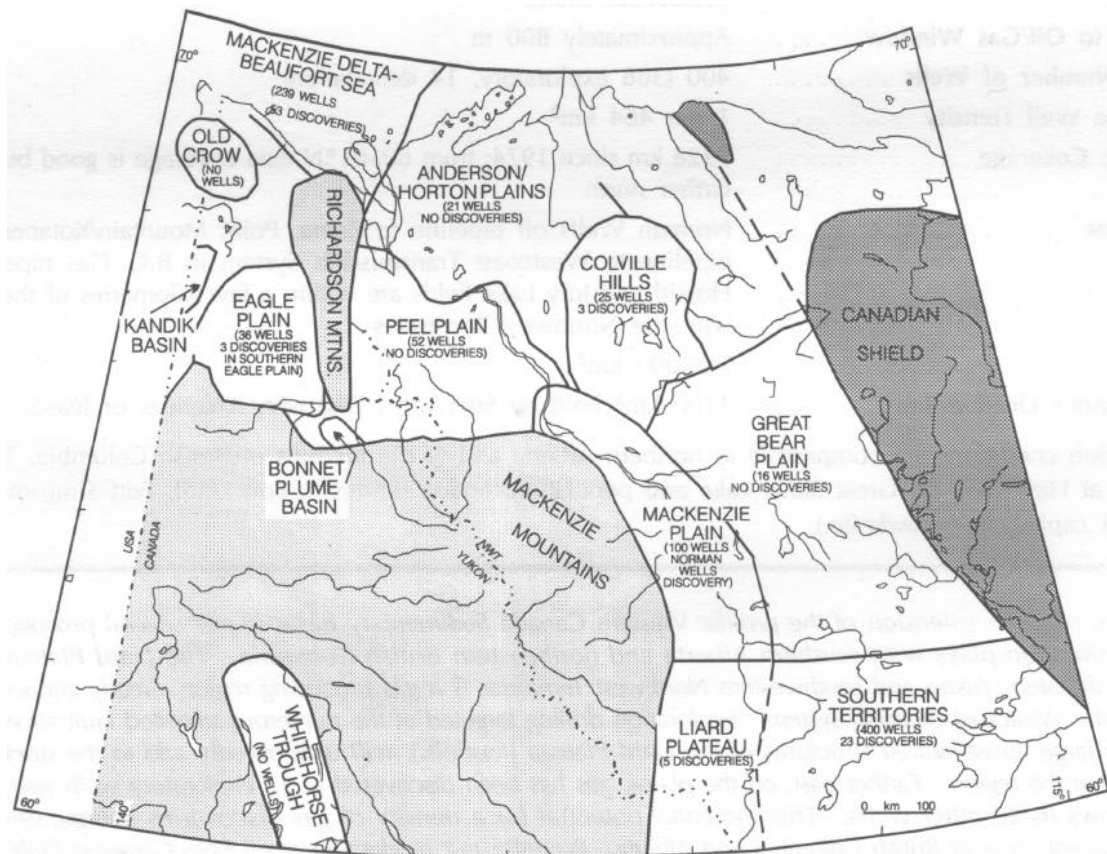


Figure 8. Exploration regions of northwest mainland Canada.

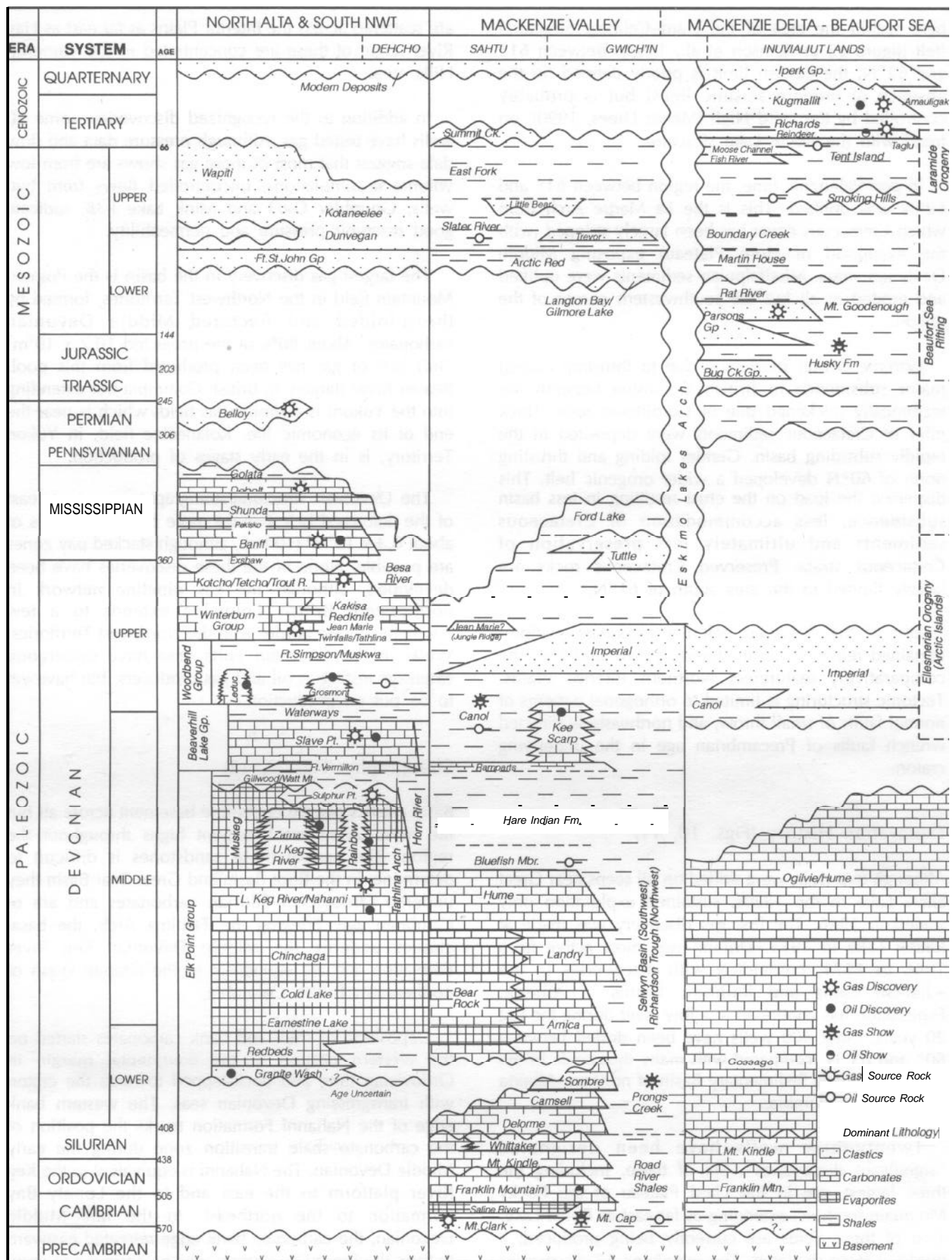


Figure 9. Table of formations for the northwest mainland Canada.

here within the area of the Liard-Celibeta Structural Belt (figure 22 in Reinson et al., 1993). Between 61° and 62°N, the eastern limit is poorly defined (in the absence of modern seismic lines) but is probably controlled by the Liard High (Meijer Drees, 1990), on trend with the Bovie Lake structure.

In post-Paleozoic time, the region between 61° and 62°N was uplifted. This is the La Martre Arch from which Cretaceous cover has been largely stripped (with the exception of Horn Plateau) exposing Middle Devonian strata. Mississippian sediments were uplifted and eroded in all but the southwestern corner of the region.

Extreme crustal shortening due to thrusting caused major subsidence in British Columbia beneath the tectonically thickened pile of Cordilleran rock. Thick piles of Cretaceous sediments were deposited in the rapidly subsiding basin. Gentler folding and thrusting north of 60°N developed a wider orogenic belt. This dispersed the load on the crust resulting in less basin subsidence, less accommodation of Cretaceous sediments and ultimately less preservation of Cretaceous strata. Preserved Cretaceous rocks are largely limited to the area south of 61°N.

East of the disturbed belt the carbonate platform remained relatively unstructured. It now underlies the comparatively featureless Northern Interior Plains. Tectonic structuring is limited to orthogonal patterns of normal faults of small throw, and northeasterly directed wrench faults of Precambrian age in the underlying craton.

Exploration History (Figs. 10, 11)

Although two wells were drilled on oil seeps near Great Slave Lake in the 1920s, sustained exploration only started in 1946. The first gas discovery was made at Rabbit Lake in 1955. Drilling was most active from 1966 to 1971, coinciding with discoveries in the adjacent Zama and Rainbow basins in Alberta. Exploration has continued at a low level during the last 20 years. Only 400 wells have been drilled between 60° and 63°N, compared with many thousands in the Western Canada Sedimentary Basin of northern Alberta and British Columbia.

Twenty-three wells have been designated "significant discoveries". Six of these, including the three largest, are in the Liard Plateau of the Rocky Mountain foothills, extending as far east as Bovie Lake. Two of these fields are currently being produced; a third has been depleted. The remaining 17 discoveries

are scattered across the Interior Plains as far east as Hay River. Eight of these are concentrated in the Cameron Hills area.

In addition to the recognized discoveries, some 20 wells have tested gas. Although pressure data and flow data suggest that most of these gas shows are from low volume accumulations, uncontrolled flows from two wells, Grumbler G-63 and Mink Lake I-38, indicate good reservoir pressure and permeability.

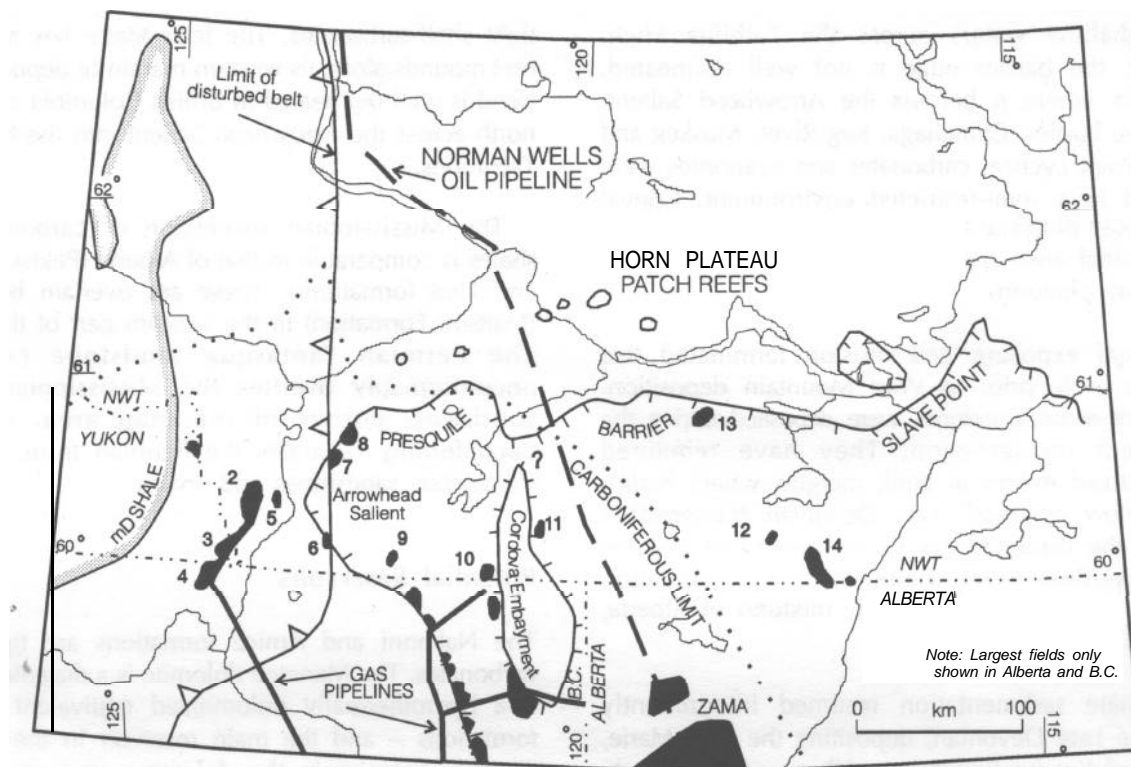
The largest gas discovery in the basin is the Pointed Mountain field in the Northwest Territories, formed by thrust-folded and fractured Middle Devonian carbonates. About 80% of the projected 10.2 x E9 m³ (360 bcf) of gas has been produced from this pool. Beaver River (largely in British Columbia but extending into the Yukon) is a similar gas field, which is near the end of its economic life. Kotaneelee field, in Yukon Territory, is in the early stages of production.

The Devonian Structural/stratigraphic gas pools east of the deformed belt average more modest reserves of about 0.3 x E9 m³ (10 bcf), although stacked pay zones are possible. None of these discoveries have been developed, although the gas pipeline network in northeastern British Columbia extends to a few kilometres of the border with the Northwest Territories. Wells in the Cameron Hills area have undergone extensive testing as oil and gas producers, but have yet to be put on production.

Stratigraphy (Figs. 9, 12)

Basal clastics overlie crystalline basement across all but the most prominent basement highs throughout the region. The age of these sandstones is difficult to determine: in the Root Basin and Great Bear Basin they underlie Ordovician-Silurian carbonates and are of Cambrian age. Fringing the Tathlina Arch, the basal clastic underlie the Middle Devonian Keg River Formation and are equivalent to the Granite Wash of northeastern British Columbia.

Deposition of shelf and bank carbonates started on the western portion of the continental margin in Ordovician time and backstepped towards the craton with transgressing Devonian seas. The western bank edge of the Nahanni Formation marks the position of the carbonate-shale transition zone during the early Middle Devonian. The Nahanni is equivalent to the Keg River platform to the east and to the Lonely Bay Formation to the northeast. In the late Middle Devonian, the carbonate bank edge retreated eastward to form the Presqu'île Barrier, which continued to grow



DISCOVERIES

1. La Biche
2. Pointed Mountain
3. Kotaneelee
4. Beaver River
5. Liard

6. Bovie Lake
7. Arrowhead
8. Netla
9. Celibeta
10. Island River

11. Trainor Lake
12. Tathlina
13. Rabbit Lake
14. Cameron Hills

- Gas Fields
- Gas Pipelines
- Oil Pipelines

Figure 10. Geological features, gas discoveries, and pipelines, southern mainland Northwest Territories.

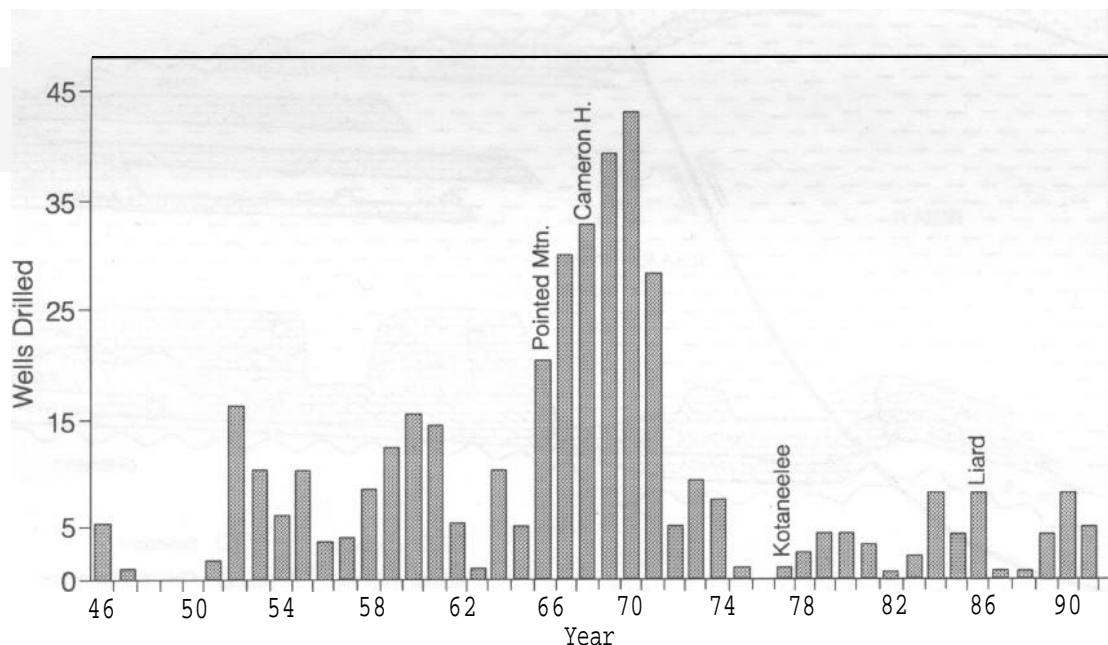


Figure 11. Drilling history, southern mainland Northwest Territories and adjacent Yukon.

in the shallow waters across the Tathlina High. However, the barrier edge is not well delineated, particularly where it borders the Arrowhead Salient. Behind the barrier, Chinchaga, Keg River, Muskeg and Sulphur Point cyclical carbonates and evaporites were deposited in a semi-restricted environment. Coeval Horn Plateau pinnacle and patch reefs have been found in the basinal areas north of the barrier, overlying the Lonely Bay platform.

Subaerial exposure and erosion terminated this carbonate cycle prior to Watt Mountain deposition. Slave Point reefal limestones were deposited during the subsequent transgression. They have remained undolomitized except at bank margins where hydrothermal flow occurred. Late Devonian transgression drowned the carbonate banks and deposited massive Horn River/Besa River shales. Note that formation names in the area are commonly mixtures of Alberta, B.C., and northern usages.

Carbonate sedimentation resumed intermittently during the Late Devonian, depositing the Jean Marie, Tetchal and Kotcho limestones. All are predominantly

tight shelf-carbonates. The Jean Marie has a trend of reef mounds along its western margin of deposition: the trend is well delineated in British Columbia and strikes north across the Arrowhead Salient into the Northwest Territories.

The Mississippian succession of carbonates and shales is comparable to that of Alberta (Pekisko, Debolt and Flett formations). These are overlain by clastics (Mattson Formation) in the western part of the region. The Permian Fantasque sandstone (= Belloy) unconformably overlies the Mississippian in the southwest corner of the map area. A major unconformity separates the Permian from overlying Cretaceous sandstones and shales.

Potential Reservoirs

The Nahanni and Arnica formations are tight shelf-carbonates. The Manetoe dolomite is a diagenetic facies - a hydrothermally dolomitized equivalent of these formations - and the main reservoir in the foothills. Average porosity in the dolomitic reservoirs is only

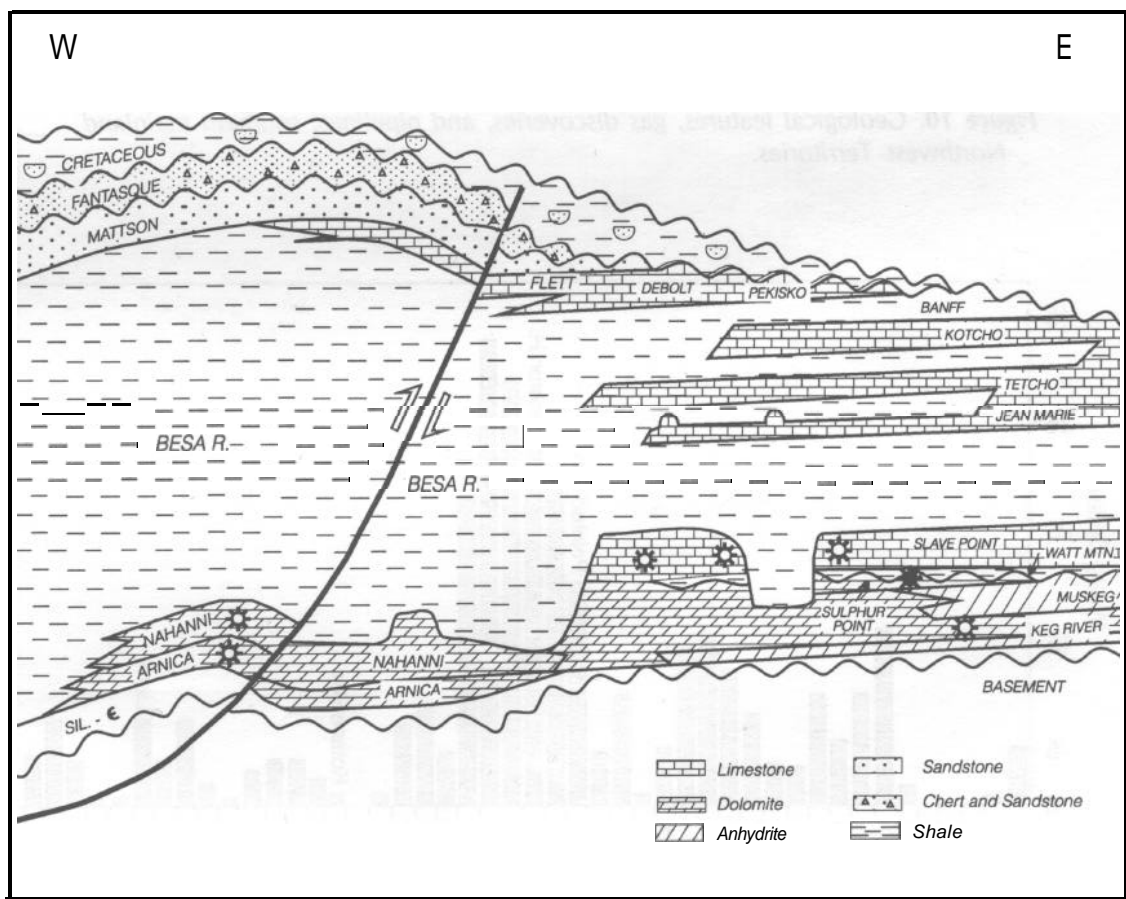


Figure 12. Schematic cross-section, southern mainland Northwest Territories.

3.5%, with permeability ranging from an average of 7 mD to 200 mD. Permeability is enhanced by fracturing. Active water drive ensures efficient production in the Pointed Mountain and Kotaneelee fields. Better porosity in the Manetoe was encountered at Bovie Lake (up to 6%), the easternmost of the foothills structures.

La Biche is an exception among foothills discoveries in that the reservoir consists of lenses of porous siltstone inter-fingering with limestone. The siltstone has an average porosity of 18% and good horizontal permeability.

The Slave Point Presqu'ile Barrier edge is a fair gas reservoir rock, averaging 7% porosity in patchy, leached and mineralized limestone at Celibeta and Netla respectively. Bank-interior Slave Point, Sulphur Point and Keg River limestones and dolomites have so far proven better reservoirs with average porosity of 9% (maximum 15%) and permeability of 7 mD (reaching 200 mD). Paramount Resources Ltd. has reported oil flows of 25.4 m³/d (160 bopd) from the Slave Point in Cameron M-73 (Daily Oil Bulletin, 17 June 1993).

Keg River dolomite reservoirs behind the Prequ'ile Barrier average 4% vuggy porosity, with effective porosity and permeability enhanced by fractures close to reactivated fault zones. Horn Plateau pinnacle and patch reefs are undolomitized and relatively tight, although 6% porosity and permeability is certainly present in these rocks at Mink Lake I-38. The Lonely Bay platform also contains a dolomitized zone with good porosity in this well.

Upper Devonian carbonate reservoirs are low porosity and poorly productive in northeastern B.C. Porous zones in the Jean Marie, Kotcho and Tetcho formations may have enhanced reservoir characteristics over fault zones in the Liard-Celibeta Structural Belt.

Carboniferous to Cretaceous clastic rocks have fair to excellent reservoir characteristics. Porosity in basal Cretaceous sandstones is in excess of 20%.

Structure, Traps and Seal

By far the most prolific hydrocarbon traps in this basin are the foothills plays in the west. Devonian carbonates, folded and thrustured during the Laramide orogeny, form large traps with relatively low porosity but excellent fracture permeability. The best example for this play type is the Pointed Mountain gas field. Diagenetic, and structural and stratigraphic traps occur along a zone of interplay between the eastern limit of orogenic

structuring and western limits of the Presqu'ile Barrier in the Arrowhead Salient and north of the Presqu'ile Barrier along the trend of the Liard High.

The eastern Slave Point, Sulphur Point and Keg River plays are usually formed by a combination of structural (normal faulting controlling basement topography) and stratigraphic trapping. The top seal for the Nahanni and Slave Point pools are the thick Horn River/Besa River shales. Sulphur Point accumulations are sealed by the Watt Mountain shale. Keg River dolomite traps can be formed by Muskeg anhydrite top seals. Structural control – increasingly subtle at higher stratigraphic levels – has produced three stacked Middle Devonian reservoirs in the Cameron Hills area.

Source Rocks

The main source rock in this basin is the Fort Simpson/Horn River/Besa River shale, in direct contact with the Nahanni and Slave Point reservoirs. The basal shale (Muskwa) is bituminous and has the highest organic carbon content. Immature in the extreme east, the Muskwa is a mature oil source rock in the centre of the map area and a gas source rock in the west. The Keg River carbonates and Muskeg evaporites are source rocks for Keg River hydrocarbons in the Rainbow basin of Alberta and may contribute to Keg River reserves in the southern Territories.

Superior source rocks in terms of Total Organic Carbon content exist in the upper Devonian, Mississippian (e.g. Exshaw) and Cretaceous. These source rocks are overmature in the Liard basin with generation and migration of oil occurring as early as the Late Paleozoic (Morrow et al., 1993). Subsequent generation of gas and cracking of migrated oil to gas is likely to have continued throughout the Mesozoic with secondary migration of gas into the existing accumulations occurring during and after Laramide deformation.

Potential

The Geological Survey of Canada has released a resource assessment of Devonian gas resources in the Western Canada Sedimentary Basin (Reinson et al., 1993). Five mature plays with a combined potential possibly exceeding 1 tcf of gas extend north of 60°N towards the northern margin of the Presqu'ile Barrier. It is noteworthy that the structural plays of the Liard Plateau were not assessed and neither was the oil potential of this area. These endow considerable additional potential.

Table 1. Significant discoveries in the foothills of the Southern Northwest Territories and Yukon

			Initial Reserve (E6 m³)	Production to 06/30/93 E6 m³)	(E6 m³)
Pointed Mountain (NWT)	1967	Producing	10200	8545	
Kotaneelee (Y U K)	1977	Producing	5012	1038	
Beaver River (BC/YU K)	1969	(Depleted)	218	218	
			Probability levels		
			95%	50%	5%
Liard (NWT)	1986	Undeveloped	80	688	2628
LaBiche (NWT/YUK)	1970	Undeveloped	263	1171	5225
Bovie Lake (NWT)	1966	Undeveloped	128	175	239

(Note: recoverable gas resource estimates for undeveloped pools are subject to a high degree of uncertainty and have been estimated using a probabilistic method.)

Source - National Energy Board

Table 2. Significant discoveries of the Interior Plains of the Southern Northwest Territories

			Probability levels		
			95% (E6 m³)	50% (E6 m³)	5% (E6 m³)
Arrowhead G-69	1985	GAS	71 *	115 *	186 *
Arrowhead B-41	1989	GAS			
Cameron Hills M-31	1979	GAS	32	60	119
Cameron Hills F-51	1969	GAS	23 *	33 *	49 *
Cameron Hills field (multiple pools; includes 7 wells designated significant discoveries)	1986	GAS & OIL			
Celebeta H-78	1960	GAS	48	125	328
Netla C-07	1961	GAS	101	426	1801
Rabbit Lake O-16	1955	GAS	187	318	538
South Island River M-41	1964	GAS	19	45	105
Tathlina N-18	1973	GAS	43	70	114
Trainor Lake C-39	1965	GAS	10	27	75

*Wells still confidential as of 1 January 1994.

(Note: none of these discoveries have been developed: recoverable gas resource estimates are based on single well discoveries for the most part and are subject to a high degree of uncertainty.)

Source - National Energy Board

The main phase of exploration in the shallow eastern plays used 1960s to 1970s seismic data. Although the Presqu'île Barrier appears to be continuous with present seismic information, small embayments are likely, trapping small to medium size oil and gas fields. Proven and still moderately prospective play types are combined structural and stratigraphic traps along the Keg River Cordova Embayment, along the main barrier system, or in the interior areas of the carbonate bank. Horn River reefs drilled north of the barrier contain little oil or gas, possibly due to a migration problem between source and reservoir rock and, in some cases, to breaching of the reservoir. Further exploration of this play may find local areas where conditions for migration, porosity development and preservation have been more favourable.

Jean Marie reef mounds are the reservoir for the producing gas field at July Lake, B.C. Comparable reservoir facies are likely to exist within the Cordova Embayment north of 60°N. A seismically defined Jean Marie barrier-reef-trend is located along a north-south trend between latitudes 122° to 123°W. This is an extension of the reef trend in Northeastern B.C. which has producing gas wells. Faulting along the western margin of the Arrowhead Salient and fracturing due to tensional drape of overstepping carbonates across underlying bank edges may augment permeability in the Jean Marie and in other upper Devonian carbonates.

The greatest remaining potential for large gas pools lies in the foothills where Devonian carbonates are folded and thrust into huge structural traps. Surface geology can identify prospective areas, but modern seismic is necessary to pick the best subsurface drilling locations: all of the foothills discoveries lack good subsurface control. This foothills play should extend north to 61°N as a broad fairway, and as a narrower, more easterly trend near longitude 123°W, all the way to 62°30'N. The western limit of the play in the Yukon is the carbonate-shale transition: this is ill-defined in the subsurface. Farther to the north and west, the Devonian section is at outcrop. The existence of a gas pipeline to the Pointed Mountain gas field makes further exploration along this broad trend economically attractive.

Largely unexplored potential remains within Mississippian and younger rocks of the deepest part of the basin west of 120°W where the Cretaceous cover has not been removed by erosion. Play types here may range from Mississippian or Permian subcrop plays to Cretaceous fluvial channels.

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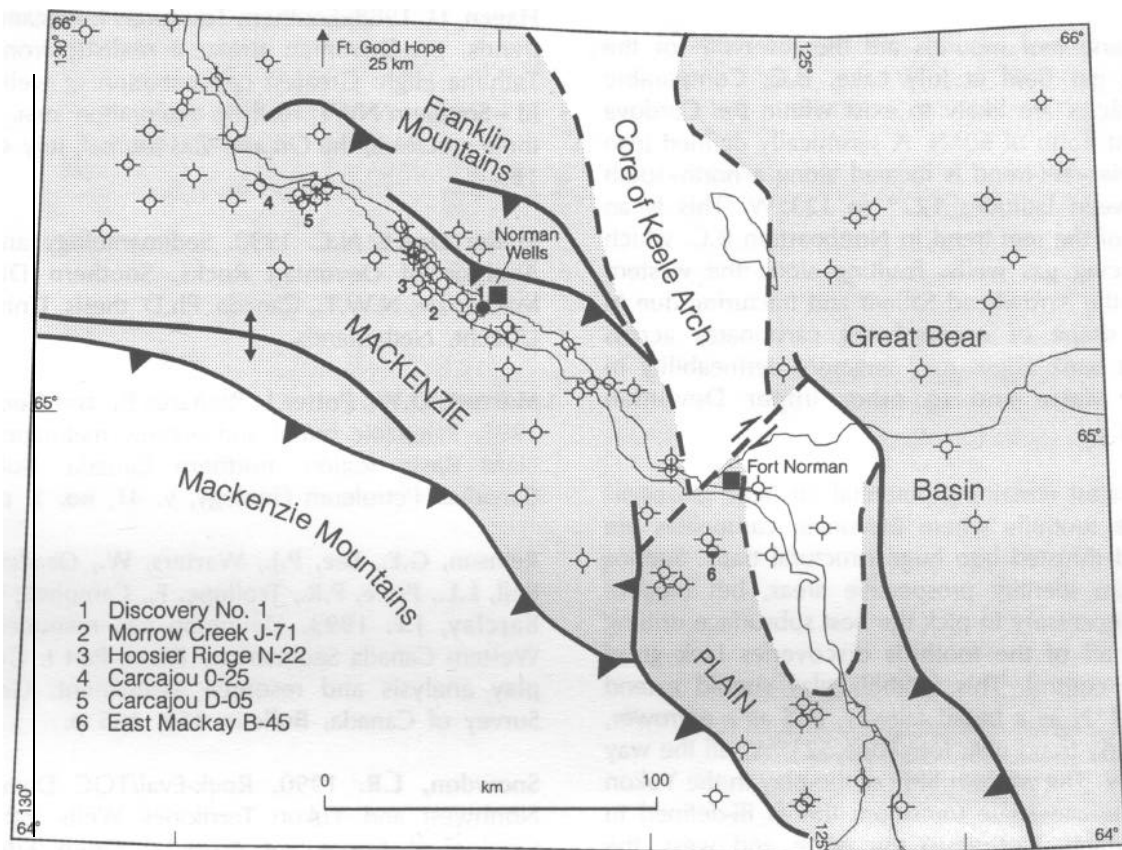


Figure 13. Geological and geographical features of Mackenzie Plain and adjacent areas.

MACKENZIE PLAIN

Age	Proterozoic to Early Cretaceous
Depth to Target Zones	500 to 4500 m
Maximum Basin Thickness	Cretaceous and younger - 3000 m
Hydrocarbon Shows	Subsurface oil and gas shows in Devonian to Cretaceous rocks, surface oil seeps
First Discovery	1920 (Northwest Discovery No. 1; Middle Devonian Kee Scarp Formation - oil)
Discovered Resources	Gas: (gas shows) Oil: Norman Wells (37.5 x E6 m ³ : 235 mmbbls recoverable)
Production	Gas: (none) Oil: 18 x E6 m ³
Basin Type	Cretaceous-Tertiary foreland basin over Paleozoic continental margin
Depositional Setting	Shallow-water carbonate shelf (early Paleozoic) clastic shelf (Late Devonian); fluvial to marine shelf (Cretaceous-Tertiary)
Reservoirs	Middle Devonian carbonates, potentially Ordovician-Silurian carbonates, Cretaceous sandstones
Regional Structure	Westward dipping monocline, uplifted and thrust in west. Salt related swells and withdrawal structures. Well defined zones of wrench faulting. Deep-seated thrust detachments
Seals	Thick Devonian shales, Cretaceous shales
Source Rocks	Mature Devonian shales (oil-prone); Lower Cretaceous shales (oil-prone)
Depth to Oil/Gas Window ...	Devonian - at surface Cretaceous - ?1000 m
Total Number of Wells	76 exploratory; 345 development at Norman Wells
Seismic Coverage	Good coverage
Pipelines	Norman Wells oil pipeline to Zama, Alberta

(Forested, low-relief flood plain bordered by rugged mountains. Easy access for heavy equipment by barge on the Mackenzie River or by winter road. Population and service centres at Norman Wells and Fort Norman. Skilled local labour force and contractors.)

Relatively well explored in pursuit of a second Norman Wells oilfield, Mackenzie Plain lies in the accessible mid-section of the Mackenzie Valley, north and south of Norman Wells. Although exploration has been focused on the discovery of further pools of Norman Wells type, other plays exist, notably in Cretaceous sandstones, which interfinger with oil-prone source rock. A high degree of structuring creates much variation in source rock maturity and juxtaposition of diverse potential reservoir units, both clastic and carbonate. Potential for further discoveries in this area ranges from moderate to high. Pool sizes are expected to show an extreme range and contain a variety of hydrocarbon types ranging from heavy to light oil, and possibly gas in the deepest parts of the basin. The area is close to an existing oil pipeline and service centre.

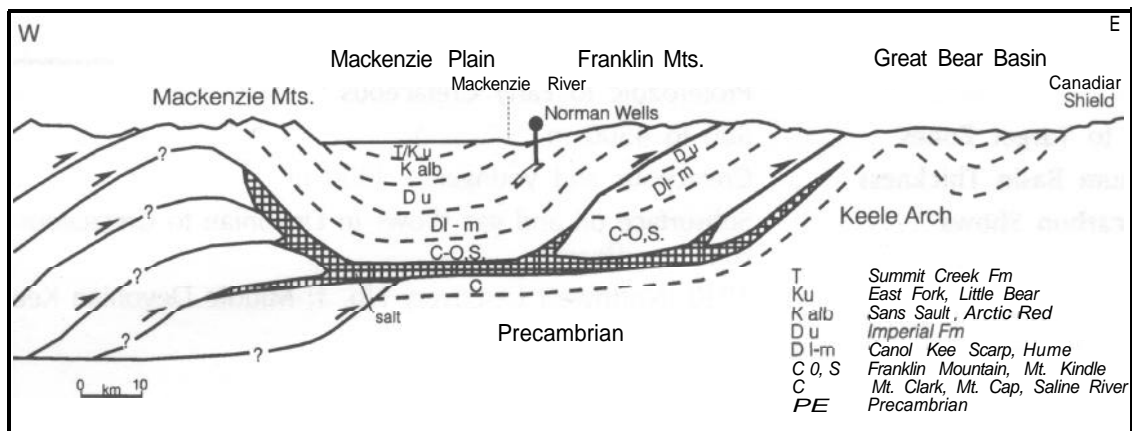


Figure 14. Schematic cross-section across Mackenzie Plain.

Geological Setting (Fig. 14)

Mackenzie Plain overlies the southern Peel Trough between the arc of the Cordillera (Mackenzie Mountains) to the west and the flank of the Keele Arch (Franklin Mountains) to the east. A westward thickening wedge of Cretaceous-Tertiary strata overlies a broad Lower Paleozoic syncline with a gently dipping eastern limb and a more steeply dipping western limb rising to outcrop as the front ranges of the Mackenzie Mountains. Lower Paleozoic strata outcropping in the Franklin Mountains border the Peel Trough to the east. The trough widens to the northwest where the Mackenzie Mountains swing westwards. The Mackenzie Foldbelt in this northern area extends beneath Mackenzie Plain. To the south, the trough becomes increasingly constricted as the Keele Arch reaches a terminus close to the Mackenzie Mountain front at about 64°N. The entire region has been affected by compressional tectonics, expressed as long wavelength folds (especially in the north), bedding-parallel detachments (beneath Mackenzie Plain), and thrust faults outcropping in the Franklin Mountains.

Exploration History (Fig. 15)

Oil seeps along the banks of the Mackenzie River have long been known and used by people of the Dene nation. They were recorded by Alexander Mackenzie during his descent of the river in 1789. The seepages at Norman Wells first attracted commercial interest in 1891 when they were pointed out to J.K. Cornwall of the Northern Trading Co. In 1919 Imperial Oil Co. acquired the Norman Wells prospect and in the following year drilled Northwest Discovery No. 1. Subsequent delineation has proved 37.5 x E6 m³ (235

million barrels) of recoverable oil pooled in the up-dip end of a Middle Devonian Kee Scarp reef within 600 m of the surface.

In the early 1940s the Canol Project involved the construction of a pipeline from Norman Wells to a refinery at Whitehorse (Yukon Territory) in support of the war effort in the Pacific theatre. Flow through the pipeline peaked at 700 m³ (4400 barrels) per day but ceased after the war and the pipeline was dismantled. Post-war production supported the refinery at Norman Wells, which processed an average of 425 m³ (2675

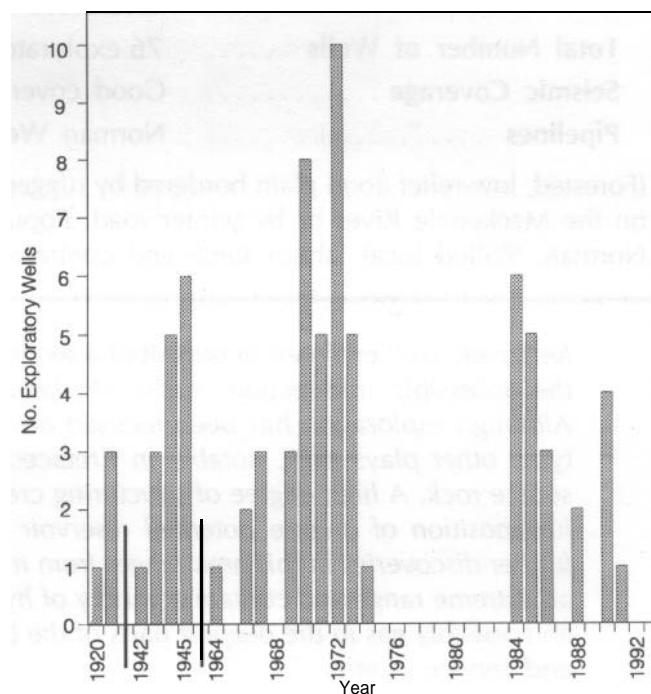


Figure 15. Drilling history, Mackenzie Plain.

barrels) per day for northern consumption. In the early 1980s, a major expansion of the Norman Wells field was undertaken, which together with the construction of a 305 mm (12") pipeline to Zama (Alberta), completed in 1986, has enabled this field to become one of the top producing fields in Canada.

Exploration activity increased in the late 1960s and 1970s and a total of 76 exploratory wells were drilled in the Mackenzie Plain, most in a narrow corridor close to the river. Farther to the east and west exploration has been sparser. In the early to mid-eighties exploration focused on the Middle Devonian reef complex northwest of Norman Wells but declined in the last half of the decade because land issuance was suspended during land claim negotiations. The limited drilling in the late 1980s concentrated in the region south of Fort Good Hope and on the Mackenzie Plain southwest of Fort Norman. In 1994, the Government of Canada issued a Call for Nominations, which included the Mackenzie Plain area and may presage renewal of exploration.

A good reconnaissance grid of seismic has been shot over the extent of the Kee Scarp play in the vicinity of Norman Wells. Farther northwest and south of Fort Norman there have been fewer seismic programs. Only one 3-D seismic program has been shot in the area (at Norman Wells).

Stratigraphy (Fig. 16)

A basal Cambrian clastic section overlies Proterozoic rocks throughout the region - at considerable depth in the Peel Trough, rising to outcrop east of the region. Sandstones of the Mount Clark Formation are gas-bearing in the Colville Hills to the northeast and are likely to exist at depth beneath the Mackenzie Plain. Cambrian deposition culminated in the deposition of evaporites - the Saline River Formation - which were superseded by widespread carbonate deposition for the remainder of the Early Paleozoic.

The Lower Paleozoic carbonate platform in the Northwest Territories comprises the Ordovician Franklin Mountain and Silurian Mount Kindle formations overlain by Lower Devonian platform carbonates, reefs and associated evaporitic facies - the Bear Rock, Arnica, Landry and Hume formations. Reef-forming carbonates of Keg River, Sulphur Point and Slave Point formations, present in the southern Northwest Territories, are represented by the shaley Hare Indian Formation in the Norman Wells area. Conditions favourable to reef development returned to

the Norman Wells area and much of Sahtu in the late Middle Devonian which saw the growth of Ramparts Formation (Kee Scarp) reefs. Reef development was terminated by deposition of Canol shale in the late Devonian, followed by the thick clastic wedge of the Imperial Formation. The Jungle Ridge Formation is a thin limestone marking a mid-Imperial hiatus in clastic input to the basin.

Albian and Upper Cretaceous strata are widely preserved and overlie the Imperial Formation above a major unconformity. Potential reservoir sandstones include the Slater River, Little Bear and East Fork formations. Local deltaic influx is evident from clinoforms visible on seismic in some of these units. The lower Tertiary Summit Creek Formation is locally preserved in the vicinity of Fort Norman. Cretaceous depositional patterns may have been influenced by syndepositional structuring related to limited mobilization of Saline River salt.

Permo-Triassic, Jurassic and pre-Albian strata are absent from the area.

Potential Reservoirs

The Middle Devonian Kee Scarp Formation at Norman Wells is the sole producing reservoir in the region. The field is in foreslope, reef margin and reef interior lagoonal facies of an atoll-type reef, which built up to 150 m above a regional limestone platform. Porosity development in the Kee Scarp reservoir at Norman Wells is unusual - micro-leaching has developed a chalky porosity ranging from 12-20% with fine but consistent pore throat size. The reservoir has good horizontal but poor vertical permeability and production is closely tuned to geological zonation of the reservoir. Thin bioclastic shoals are associated with the leeward side of the Norman Wells reef. These may have a more widespread if discontinuous distribution across the regional platform and may be comparable to patchily distributed bioclastic sandstone encountered immediately above the reef and below the Canol shale - the Charrue sandstone. Where highly fractured, the Canol shale has potential as a low volume producer in its own right.

Most of the recent wells in the Middle Devonian reef facies have penetrated back reef or lagoonal facies; one well flowed salt water at good rates (PC1 Morrow Creek J-71), and cores from PC1 Hoosier N-22 and AT&S Carcajou O-25 bled oil. Gas with a heavy salt water spray flowed from a fractured zone in AT&S Carcajou D-05.

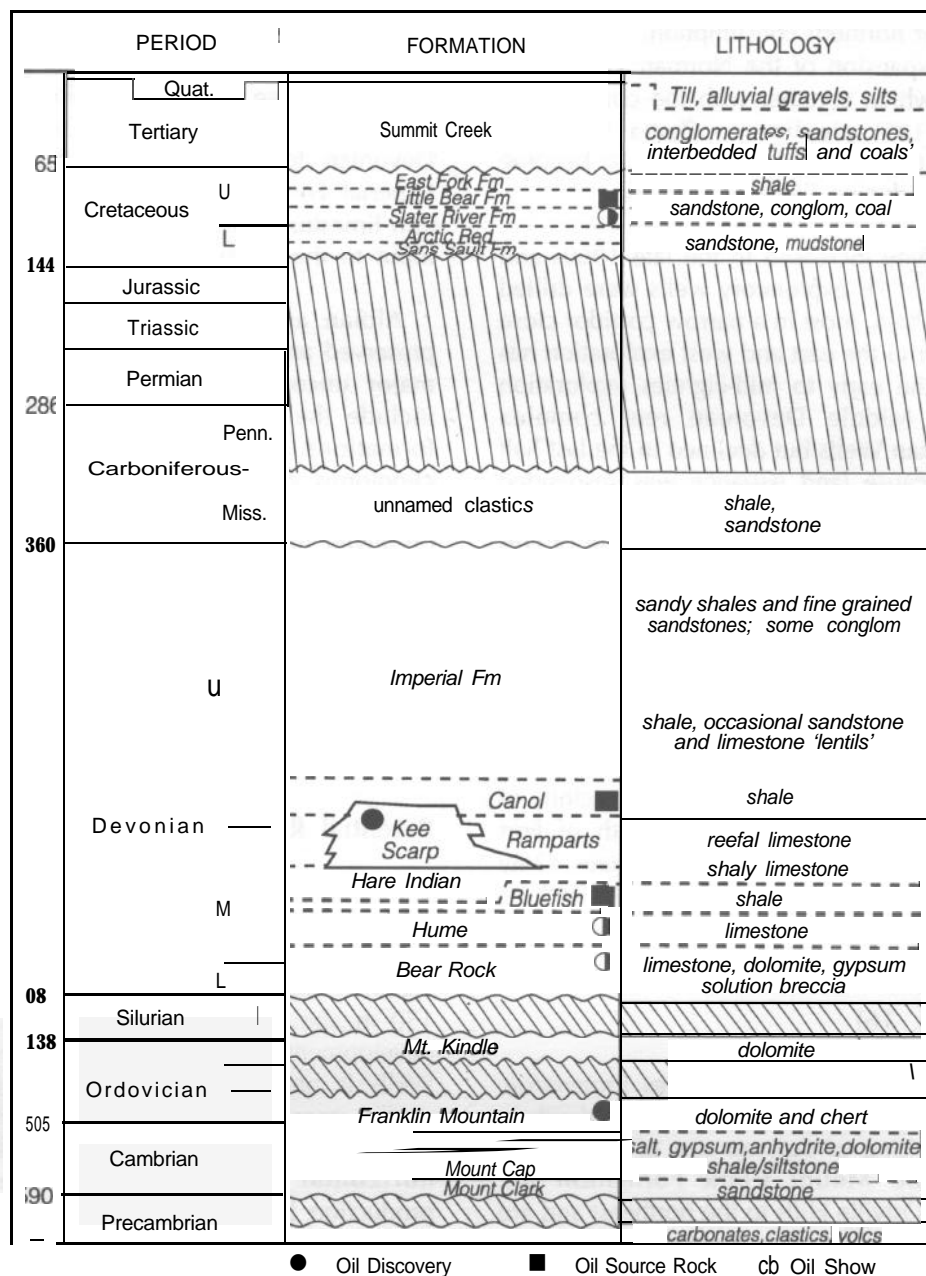


Figure 16. Table of formations, Mackenzie Plain area.

The Lower Devonian Bear Rock carbonates and evaporites are extensive in the subsurface of Mackenzie Plain. The Bear Rock commonly has cavernous porosity in subsurface occurrences. Minor oil staining has been reported in the Bear Rock near the western transition from anhydrite to carbonate. All porous zones tested to date have flowed water, but this unit is potentially an excellent reservoir if isolated from the regional aquifer. Other Lower Devonian formations also have reservoir potential - either in intergranular and vuggy porosity developed in platform carbonates, or locally as pinnacle reefs building from the Hume platform. A shallow and breached example of the latter was drilled

by the Atlantic Col Car Manitou Lake L-61 well near Fort Good Hope.

Candel East Mackay B-45 had pipe recovery of 20° API oil from fractured cherts of the Upper Cambrian-Ordovician Franklin Mountain Formation. Potential for fractured reservoir development is fair in Laramide structures containing brittle Lower Paleozoic units. There is also a possibility of deeper clastic reservoirs in the Cambrian beneath the Saline River but, if similar to the Colville Hills gas reservoirs, they are unlikely to have porosity exceeding 12%.

Structure, Traps and Seal

Laramide deformation of the previously mildly deformed Paleozoic margin developed a variety of fold, thrust and wrench structures, each of which is quite localized and separated by areas where deformation is minimal. The area and style of deformation is linked to the distribution of the Saline River salt, which forms a major decollement surface. Bedding-parallel detachment and eastward translation of broad panels of post-Cambrian strata are demonstrated by mapped overthrusts east of the Norman Range.

Large amplitude folds related to a deep-seated detachment are apparent in the Mackenzie Mountains, which border on the west of the region. These structures extend beneath Mackenzie Plain in the north; for instance, at the Imperial anticline. In the central part of the valley, west and southwest of Norman Wells, the regional dip is to the west. As the Mackenzie Mountain front is neared, a dip reversal occurs above a deep triangle zone comprising imbricate thrust panels.

South of Fort Norman a major discontinuity is apparent in the alignment of mountain ranges and the course of the river. This discontinuity marks a zone of wrench faulting, which runs at an oblique angle across the fold axes of the Mackenzie and Franklin mountains towards the Smith Arm of Great Bear Lake (the "Fort Norman Structure" of Aitken and Pugh, 1984). Major thrust folds are associated with this wrench system, which follows the trend of pre-Cretaceous extensional faulting. Structural deformation in the area is influenced by the Cambrian salt: swells and withdrawal collapse structures are apparent, but no diapirs have been noted.

Lower Paleozoic strata are upturned and truncated along the western flank of the Keele Arch. Sub-unconformity traps may be created in this area by overlying Cretaceous shales.

Source Rocks

Norman Wells oil is derived from the Canol Shale draping the reef. The Canol is responsible for most of the oil seeps along the Mackenzie River. The Canol is widely developed and geochemical studies demonstrate that its potential as a source rock for oil is sustained throughout most of the region. A lithologically similar but older unit – the Bluefish Member of the Hare Indian Formation – is also a rich, oil-prone source rock. Both of these source rocks are just within the oil window at the current subsurface depth of the Norman Wells field although the oil is more mature, indicating a source at greater depth of burial. Higher maturation levels,

possibly to beyond the lower limit of the oil window are likely in deeper parts of the basin nearer the Mackenzie Mountains.

Oil recovered from the Franklin Mountain Formation at East Mackay correlates to a source rock in the Cretaceous Slater River Formation (Feinstein et al., 1988). This unit is regionally extensive and its variable depth throughout the basin suggests a spectrum of maturity. Oil staining also has been observed in Cretaceous sandstones in several wells (for example, oil cut mud (25-30° API) recovered from Mesa Hanna River J-05.

Potential

Large reefal developments north of Norman Wells have been partially delineated by existing seismic and wells. The exploration potential of these areas for pools of Norman Wells type has been summarized by G.K. Williams (1986). There remain opportunities to discover oil pools along the up-dip edges of the reef masses and within the complex architecture of the reef where source, seal and porosity development coincide. Proximity to outcrop in the Franklin Mountains with risk of reservoir breaching, biodegradation of oils, and uneven porosity development are the principle risks in this play.

In the vicinity of the Norman Range, the prospective Middle Devonian section may be repeated beneath the thrust sheet carrying the Norman Wells field. Low relief shoals developed above the regional carbonate platform may be additional targets for small oil accumulations: these are barely resolved by seismic.

Imbricate thrusting close to the Mackenzie Mountain front, Laramide thrust folds and pre-Laramide folds and fault blocks are less explored structural targets. The Cretaceous section has potential for oil pools in structural/stratigraphic traps which may be of interest because of the close proximity of production facilities at Norman Wells. Potential for good quality reservoir rock in the Cretaceous is high.

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PEEL PLAIN AND PLATEAU

Age	Paleozoic, Cretaceous
Depth to Target Zones	1000-4000 m
Maximum Basin Thickness	4000 m close to mountains
Hydrocarbon Shows	Gas shows in several wells, bitumen
First Discovery	No discoveries
Basin Type	Cretaceous foreland basin over Paleozoic continental margin
Depositional Setting	Marine carbonate platform to basin (early Paleozoic); marine shelf (late Devonian); alluvial to marine shelf (Cretaceous)
Potential Reservoirs	Lower Paleozoic platform and shelf-edge carbonates; Imperial/Tuttle sandstones; Cretaceous sandstones
Regional Structure	Southwestward dipping monocline bordered to west and south by erogenic belts
Seals	Lower and upper Paleozoic shale tongues; Cretaceous marine shales
Source Rocks	Road River Group, Bluefish and Canol shales; Mississippian Ford Lake Shale
Depth to Oil Window	Approximately 1000 m
Total Number of Wells	52 (in rectangle 65-67°30'N, 130-136°W)
Seismic Coverage	Sparse reconnaissance
Area under Licence	None

(Accessible from population centres at Fort MacPherson and Fort Good Hope. Barge transport of heavy equipment' on the Mackenzie River. Terrain: low elevation, muskeg, incised river valleys.)

Fifty-two wells have been drilled in this region with some significant shows of gas reported. Overall potential increases from low to moderate in the northeast to moderate to high in the southwest as the sedimentary succession increases in thickness and completeness, and as maturity of potential source rocks increases with depth of burial. Potential for large structural traps is localized in zones paralleling the Richardson and Mackenzie mountains: elsewhere potential lies in stratigraphic traps transverse to regional dip in fluvial, valley fill and possibly deltaic Cretaceous sandstones, in shelf sandstones of the Imperial Formation or in deltaic sandstones of the Paleozoic Tuttle Formation. Reefs of middle Devonian age are known to exist near the eastern edge of Peel Plain and the presence of isolated reefs building from the Hume platform is likely.

Geological Setting (Fig. 17)

North of 65°N, the Cordillera swings to the west and relatively undisturbed sedimentary strata are preserved across a broad area west of the Mackenzie River. This area, known as the Peel Plain and Plateau, is underlain by a wedge of Cretaceous strata thickening to the west

and south that was deposited in a foreland basin setting, typical of the Western Canada Sedimentary Basin. The Mesozoic strata overlie Paleozoic strata preserved within the Peel Trough, the axis of which is sub-parallel and outboard of the Mackenzie Foldbelt. A wedge of upper Paleozoic strata is preserved in the southwest corner of the region.

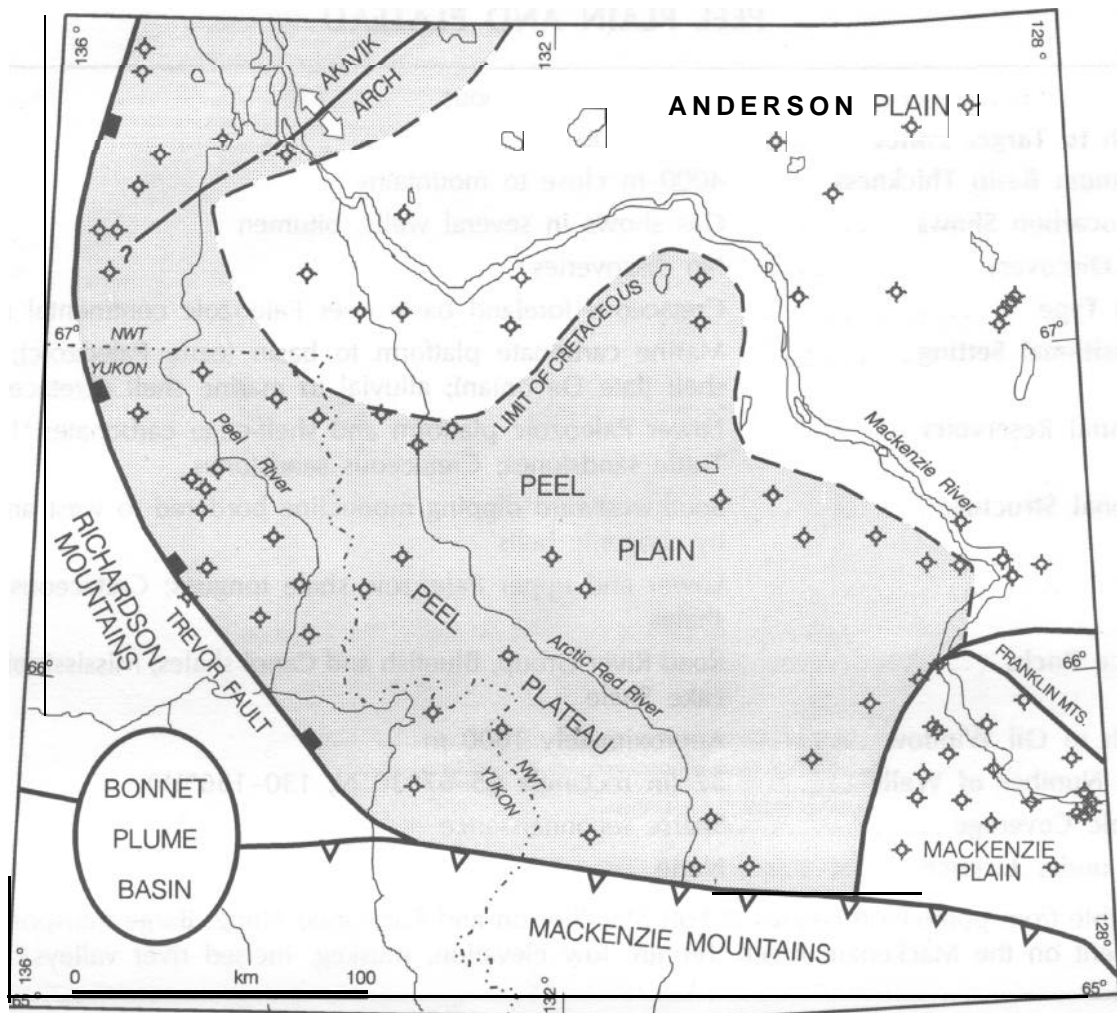


Figure 17. Geological and geographical features, Peel Plain and Plateau.

The western and southern margins of the region border the Richardson Mountains and Mackenzie Mountains respectively. Significant structuring of the Paleozoic and younger rocks appears limited to relatively narrow zones bordering the mountain belts.

logs indicate good porosity in the Devonian carbonate section.

Drilling has been concentrated in corridors close to the Mackenzie River, and in the Peel River drainage area in the Yukon. The central area of Peel Plain is sparsely drilled.

Exploration History (Fig. 18)

The first well to be drilled on Peel Plain was Richfield Oil Corp. et al. Grandview Hills No. 1 A-47 spudded in 1959. The well was abandoned at 1998 m after penetrating to the Franklin Mountain Formation. The main phase of drilling lasted a decade, beginning in the mid-sixties, but with no significant success. The most significant show was encountered while drilling the Shell Tree River H-38 where flows of sweet gas, estimated at $17.7 \times 10^6 \text{ m}^3$ (0.5 mmcf/d) occurred during loss of well control at 721 m (2366 ft.). Several lost circulation zones were encountered while drilling. The

Stratigraphy (Fig. 19)

The Cambrian section is deeply buried beneath the Peel Plateau: units include thin distal equivalents of the Mount Clark, Mount Cap and Saline River formations, which are included as undivided Cambrian sediments at outcrop in the Richardson Mountains. Deposition of the Franklin Mountain Formation (Ordovician, 600-1000 m) marked the establishment of a broad early Paleozoic shelf dominated by carbonate deposition. The Franklin Mountain is overlain by

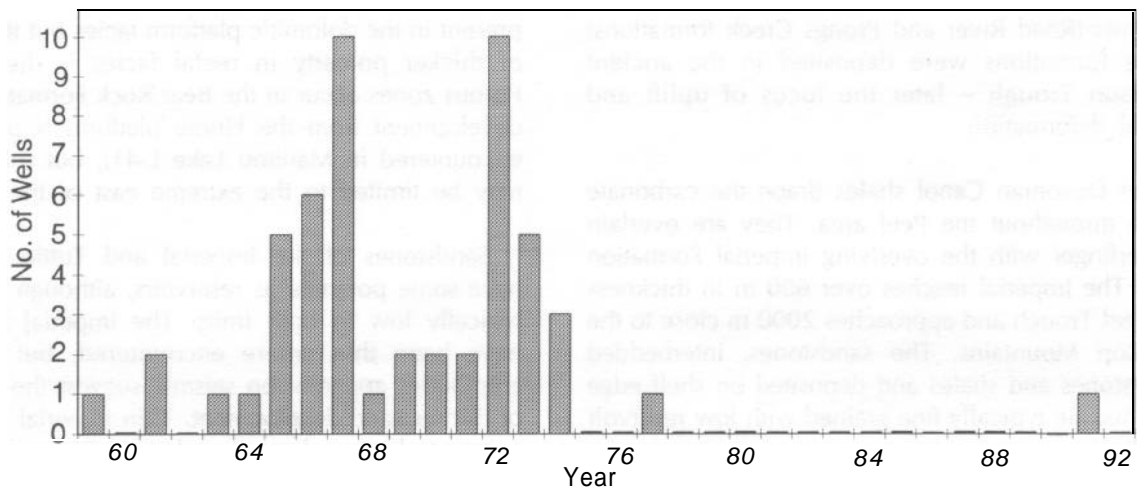


Figure 18. Drilling history, Peel Plain and Plateau.

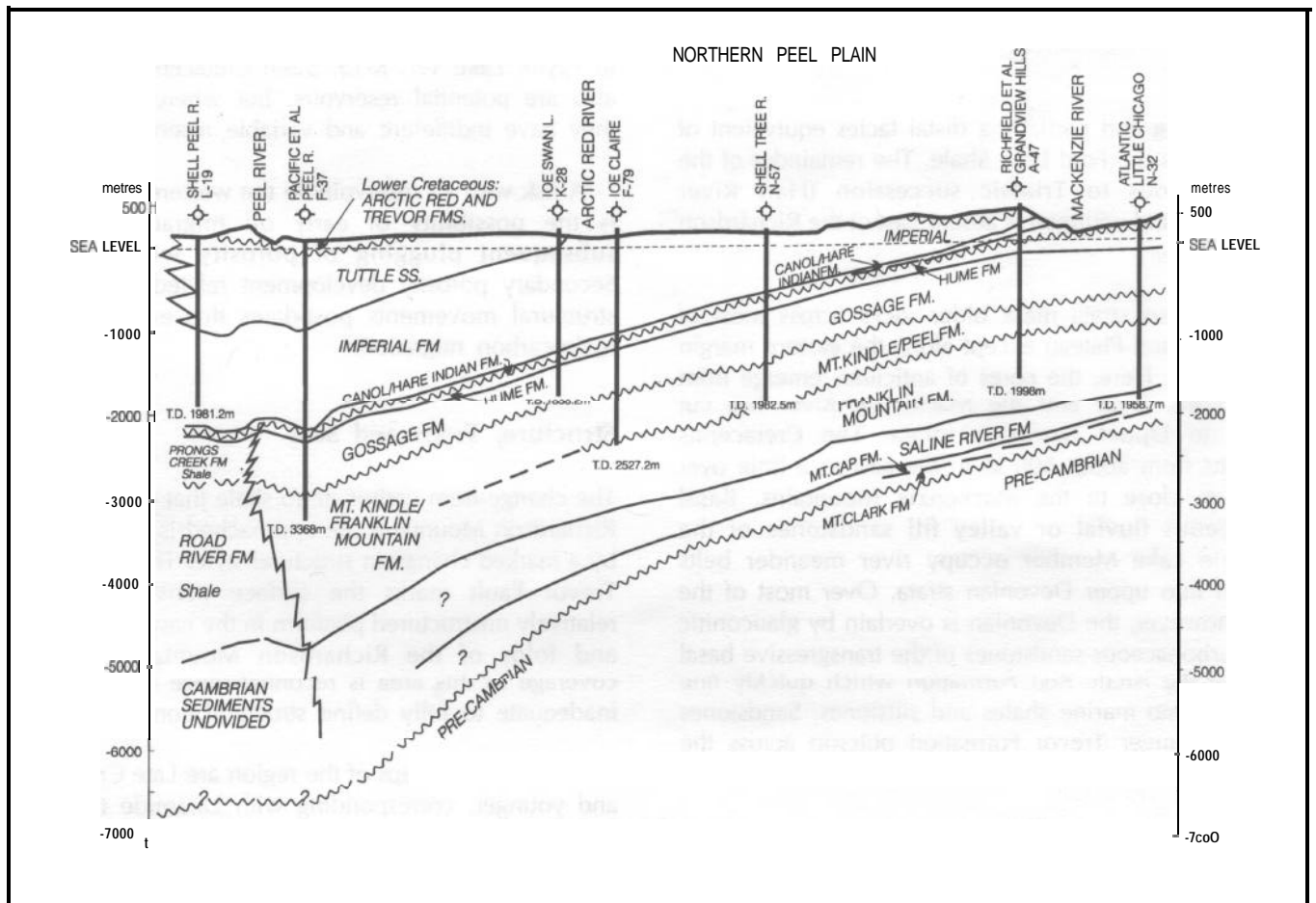


Figure 19. Schematic cross-section, Peel Plain and Plateau.

carbonates of the Mount Kindle and Peel formations (Silurian 300-800 m), in turn by the Devonian carbonate assemblage, comprising the Arnica, Landry and Hume formations (approximately 1000 m). The

lower Paleozoic carbonate platform extends from the outcrop areas in the Franklin Mountains east of the Mackenzie River to a zone of carbonate/shale transition that parallels the Richardson Mountains. Shale

equivalents (Road River and Prongs Creek formations) of these formations were deposited in the ancient Richardson Trough – later the focus of uplift and structural deformation.

Upper Devonian Canol shales drape the carbonate platform throughout the Peel area. They are overlain and interfinger with the overlying Imperial Formation clastics. The Imperial reaches over 600 m in thickness in the Peel Trough and approaches 2000 m close to the Richardson Mountains. The sandstones, interbedded with siltstones and shales and deposited on shelf edge clinoforms, are typically fine grained with low reservoir potential.

The Tuttle Formation (latest Devonian to Mississippian) is represented by repeated cycles of fine to coarse grained fluvio-deltaic sandstones and conglomerates. The formation reaches an overall thickness of 800 m in the subsurface of the lower Peel River area.

Overlying and partially a distal facies equivalent of the Tuttle is the Ford Lake Shale. The remainder of the Carboniferous to Triassic succession (Hart River Formation and younger) is absent east of the Richardson Mountains.

Cretaceous strata mask older rocks across most of Peel Plain and Plateau except along the eastern margin of the area. Here, the cores of anticlines emerge from Cretaceous cover and the Mackenzie River has cut down to Upper Devonian strata. The Cretaceous thickens from about 500 m in the east to a little over 2000 m close to the Mackenzie Mountains. Basal Cretaceous fluvial or valley fill sandstones of the Gilmore Lake Member occupy river meander belts incised into upper Devonian strata. Over most of the area, however, the Devonian is overlain by glauconitic and carbonaceous sandstones of the transgressive basal beds of the Arctic Red Formation which quickly fine upwards into marine shales and siltstones. Sandstones of the younger Trevor Formation outcrop across the Peel Plateau.

Potential Reservoirs

With no significant discoveries there are no proven reservoir rocks within the Peel area. Vuggy porosity has been noted in the Devonian and older carbonates but no systematic trend of enhanced porosity has been noted: the platform limestones fringing the Richardson Trough are typically tight. Farther east, porosity is

present in the dolomitic platform facies but the absence of thicker porosity in reefal facies is discouraging. Porous zones occur in the Bear Rock Formation. Reefal development from the Hume platform is possible (as encountered in Manitou Lake L-41), but this situation may be limited to the extreme east of the region.

Sandstones of the Imperial and Tuttle formations have some potential as reservoirs, although porosity is typically low in both units. The Imperial sandstones have been thin where encountered, but enhanced amplitudes apparent on seismic suggest the possibility of thicker sand development. Thin Imperial sandstones appear to be gas charged on logs in Chevron Ramparts River F-46. Fairways with enhanced porosity in the Tuttle are of restricted extent. Tuttle sandstones are generally poorly sorted, with kaolinitic matrix and have low porosity and permeability. Sorting and potential reservoir quality improve to the south where fine to medium grained sandstones have porosities up to 15% in Taylor Lake Y.T. K-15. Basal Cretaceous sandstones also are potential reservoirs, but where encountered they have indifferent and variable reservoir quality.

A risk with all reservoirs in the western Peel Plateau is the possibility of early oil migration and the subsequent plugging of porosity with bitumen. Secondary porosity development related to Laramide structural movements post-dates this early phase of hydrocarbon migration.

Structure, Traps and Seal

The change from carbonate to shale that occurs as the Richardson Mountains are approached is accompanied by a marked change in structural style. The north-south Trevor Fault marks the surface transition from a relatively unstructured platform in the east to the thrusts and folds of the Richardson Mountains. Seismic coverage in this area is reconnaissance in nature and inadequate to fully define structural complexity.

The structural traps of the region are Late Cretaceous and younger, corresponding with Laramide tectonics. This would appear to post-date the onset of oil generation in lower Paleozoic rocks. Potential oil source rocks in younger formations may have been in the oil window subsequent to trap formation. Stratigraphic and diagenetic traps of Upper Devonian and Lower Cretaceous rocks are more likely to have formed coeval with oil generation and migration from older source rocks.

Source Rocks

Pugh (1983) notes that thousands of metres of black shale of the Road River Formation lie in the Richardson Mountain belt. These basinal shales are juxtaposed against shelf carbonates. High TOC (2.5 to 9.6%) and Type I or II kerogen have been reported from Road River shales suggesting that certain intervals within this sequence were once excellent oil-prone source rocks. Unfortunately, maturation studies indicate that these source rocks generated hydrocarbons as early as the Late Devonian and are now overmature – this is likely to be particularly true in the deeper areas of the Peel Trough. Lower to Middle Devonian rocks may have some potential in eastern Peel Plateau as a source rock, as does the overlying Canol Formation. In western Peel Plateau, the Devonian is probably overmature for oil generation, as evidenced by the bitumen encountered in several wells.

Samples from the Upper Devonian Imperial Formation are reported as mature with fair to good gas source potential. Ford Lake shales have fair to good gas and some oil potential in eastern Eagle Plain and it is probable that similar potential exists in western Peel Plateau.

The Lower Cretaceous Arctic Red Formation is generally lean in organic carbon with terrestrial Type III kerogen predominant. On the basis of limited data, the basal Cretaceous enters the oil window at depths below 750 m.

Potential

The localization and stacking of shelf edge carbonates creates multiple potential targets adjacent to and inter-fingered with potential source rocks and seals. It is unlikely that much oil potential remains in the pre-Upper Devonian source rocks, however, these will have continued to generate gas. The major risk in this play is poor porosity development and overmaturity of source rock.

East of the shelf edge there is patchy porosity development within the carbonate platform. The

controlling factors for such porosity are not clear but there is potential for significant potential pay thickness. Large diagenetic/stratigraphic traps may occur. This play is poorly explored by drilling to date.

The Tuttle Sandstone may develop favourable reservoir characteristics in the southwestern corner of the region. This constitutes an interesting target over a limited area, principally in the eastern Yukon. The stratigraphic proximity of the Tuttle to potential oil source rocks in the Mississippian is encouraging.

An Early Cretaceous drainage system developed during the Late Aptian across a pre-Mesozoic peneplain. Potential sandstone reservoirs could occur in stratigraphic traps in this play. Oil potential in Gilmore Lake prospects may be restricted to areas where the Canol subcrops the basal Cretaceous unconformity. Arctic Red sandstones are widely distributed, although these have modest potential as low productivity gas reservoirs. Because they are marine sheet-sandstones they lack stratigraphic trapping potential and are generally unstructured.

The structural complications associated with the carbonate/shale transition create opportunities for structural/stratigraphic traps, diagenetic porosity development and migration.

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NORTHERN INTERIOR PLAINS-THE COLVILLE HILLS

Age	Cambrian, Ordovician, Early to Middle Devonian
Depth to Target Zones	1000 - 1400 m
First Discovery	Ashland et al. Tedji Lake K-24 (1974~Gas)
Discovered Resource	Gas: 11.354 x 10 ⁹ m ³ (400 bcf)-aggregate of 50% (median) estimates in 3 discoveries
Basin Type	Intra-cratonic basin (Cambrian): cratonic margin (Ordovician-Devonian)
Depositional Setting	Restricted/continental (Cambrian). Marine carbonate shelf (Ordovician-Devonian)
Reservoirs	Cambrian sandstones
Regional Structure	Northward-trending system of extension faults with superimposed transpression
Seals	Cambrian shales, evaporites
Source Rocks	Mount Cap Formation (Cambrian-oil prone); ?Precambrian
Depth to Oil Window	1500-2000 m?
Total Number of Wells	25 (21 exploratory; 3 delineation)
Area	20,000 km ²
Area under Licence	39,078 ha in 4 Significant Discovery Licences

[Low rolling hills with lakes, muskeg. Nearest population centres: Fort Good Hope on Mackenzie River (150 km), Coppermine on Coronation Gulf (475 km)]

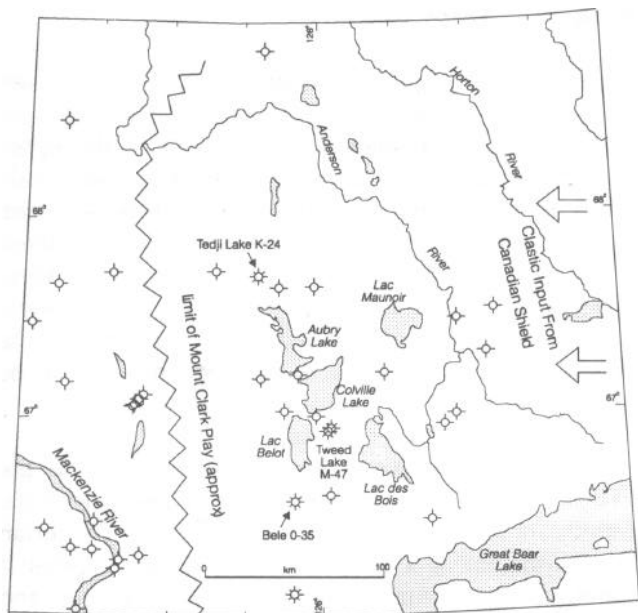
This large and sparsely explored area contains several gas discoveries in Cambrian sandstones in the Colville Hills. Prospects include large low-relief structures at depths ranging from 1100 to 7400 m. Of the three discoveries, Tweed Lake contains sweet dry gas; Tedji Lake and Bele contain substantial condensate reserves in addition to gas. Overall potential for additional gas discoveries is very high in this play with pool sizes in the range 25-300 bcf (recoverable). Oil source rocks are also present in the Paleozoic and may contribute light oil or condensate to the largely gas accumulations. The potential for small to medium sized oil pools in undrilled structures appears high.

Geological Setting (Fig. 20)

Following the development of a regional peneplain in the late Precambrian, a shallow intra-cratonic basin began to subside, flanked by the Precambrian shield to the east and the Mackenzie Arch to the west. The basin filled with a clastic to evaporitic succession of Cambrian sediments, culminating in widespread deposition of Saline River salt in the Late Cambrian. Silurian-Ordovician uplift of the Keele Arch inverted the central part of the Cambrian basin. Subsequent clastic input to the area was minimal – as elsewhere along the craton margin. There followed a long period of carbonate platform deposition lasting until the end of the Middle Devonian. Clastic deposition predominated

from Late Devonian onwards, with a major gap in the stratigraphic record between the end of the Devonian and the Cretaceous. Cretaceous strata were deposited throughout the region but have subsequently been stripped from the Colville Hills.

The influence of Laramide tectonics is apparent in the Colville Hills area as shallow, detached, wrench, compressional and extensional faults overlying reactivated deeper crustal scale faults (MacLean and Cook, 1992). Loading by the growing Cordillera began to tilt the continental margin to the west from the Cretaceous onwards, establishing a regional up-dip migration route for hydrocarbons generated in the deeper parts of the basin.



Note: Play limit from Hamblin, 1990

Figure 20. Well locations and geographic limits of Mount Clark sandstone, Colville Hills area.

Exploration History

Although large structural domes visible on aerial photographs have stimulated exploration in the Colville Hills, a larger population of prospects have no surface expression. Ashland et al. Tedji Lake K-24, the first well to discover hydrocarbons in the area, was drilled on a subsurface structure identified by seismic.

Following the issuance of exploration licences in the early eighties, exploration in the Colville Hills became

particularly active. Two additional discoveries confirmed the basal Cambrian Mount Clark sandstone as regionally extensive and a potential reservoir throughout the area. Eleven wells have been drilled in the Colville Hills resulting in three gas discoveries (two with condensate). No oil accumulations have been found although oil-staining is common. A total of 25 wells have penetrated the Mount Clark Formation throughout the Interior Plains.

Significant discoveries have been made at:

Ashland et al. Tedji Lake K-24 (1974)

PCI et al. Tweed Lake M-47 (1985)

PCI Canterra Bele O-35 (1986)

In addition, there was a significant gas show in PCI Canterra Nogha O-47 (1986).

Oil seeps in Cretaceous sandstones are common in the area and have attracted exploration interest, notably at Rond Lake, west of the Colville Hills. The expectation that the seep at Rond Lake overlay a buried Devonian reservoir was disproved by drilling.

Stratigraphy (Fig. 21)

Below the base of the Cambrian is a very thick section of Proterozoic strata with stratiform reflectors evident on seismic to depths of over 10 km. Lithologies encountered in wells include dolomite and basalt. A map of the Proterozoic subcrop beneath the Cambrian is given in MacLean and Cook (1992).

Lower Cambrian Mount Clarke Formation sandstones and siltstones up to 65 m thick overlie

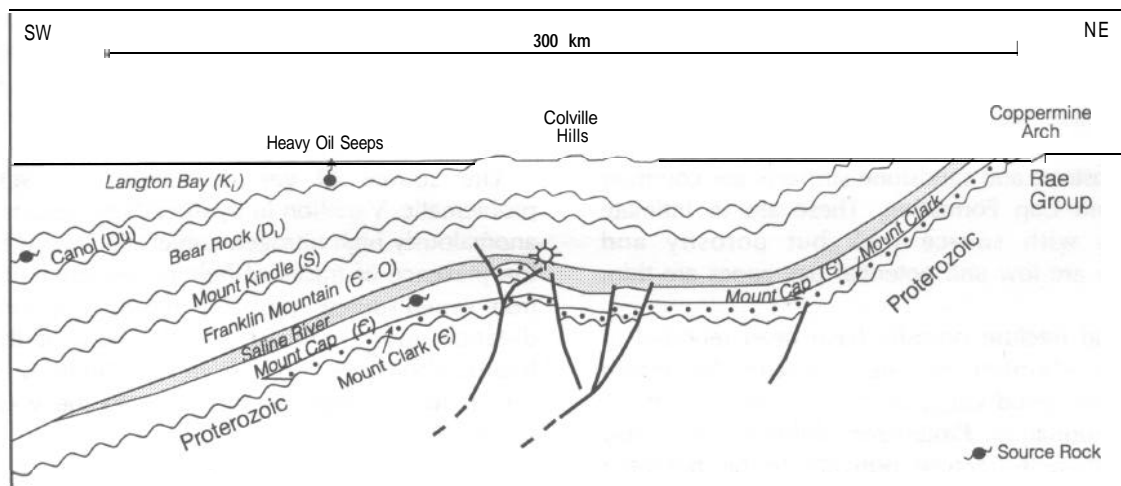


Figure 21. Schematic cross-section, Colville Hills area.

Precambrian basement (Hamblin, 1990). They are in turn overlain by Lower to Middle Cambrian shales, siltstones and thin carbonates of the Mount Cap Formation (up to 270 m), and Middle to Upper Cambrian evaporites and carbonates of the Saline River Formation (approximately 200 m). There is a gradual transition into Ordovician carbonates of the Franklin Mountain Formation (approximately 500 m) which are overlain by the Middle Devonian Bear Rock Formation above a major unconformity. Progressively younger Devonian formations subcrop the pre-Mesozoic unconformity to the west. These are the Ramparts, Canol and Imperial formations respectively.

Albian sandstones of the Gilmore Lake member of the Langton Bay Formation overlie a major unconformity, which truncates the underlying Devonian and older rocks across the Keele Arch. The basal sandstones fine upwards into the shales and siltstones of the Crossley Lakes member. The Cretaceous has been stripped from the axis of the Keele Arch, but is exposed at outcrop along the flanks of the Arch both to the east in the Great Bear Basin and to the west.

Potential Reservoirs

The Mount Clarke Formation consists of interbedded sandstone and siltstone up to 65 m in gross thickness with potential – as indicated by seismic stratigraphy – to increase in thickness off-structure. Mount Clarke sandstones are the principal reservoir rocks in the area (Hamblin, 1990). The basal Cambrian sandstone is extensive but thin – averaging less than 10 m of pay in the existing discoveries. Pay is also present in thin sandstone stringers above the basal sandstone. Average porosity in the discovered reservoir is 12%, with water saturations of 30%. Core studies indicate the better reservoir to be fine to medium grained sandstones with permeability ranging up to 500 mD, and averaging 25 mD. At Tweed Lake, gas flows up to 156,000 m³/d with condensate were tested from a 15 m interval.

Thin dolostone and sandstone stringers are common in the Mount Cap Formation. These are in intimate association with source rock but porosity and permeability are low and potential pay zones are thin.

Vuggy and fracture porosity have been reported in the Cherty Member of the Franklin Mountain Formation, and good vuggy porosity is common in the Bear Rock Formation. Proterozoic dolomites also may develop sufficient fracture porosity to be potential reservoirs.

Structure, Traps and Seal

Structural prospects are associated with faults and anticlines of the Keele Arch. Laramide normal and reverse faults have shallow detachments in the upper Proterozoic and occur above pre-existing crustal scale faults rooted within the Proterozoic (MacLean and Cook, 1992). Seismic lines traversing some of these faults display flower structures typical of local transpressional stress. It is noteworthy that several episodes of deformation/re-activation have affected the region and that pre-Laramide structures have yet to be drilled.

The Cambrian shales are effective barriers to the vertical migration of gas from the underlying basal Cambrian sandstones. At the top of the Cambrian section the salt is a seal of regional extent, capping a Cambrian petroleum system containing source and reservoir rock (Jones et al., 1992). Lower Paleozoic strata above the salt lack good seals.

Source Rocks and Oil Seeps

Thin source rocks rich in alginite have been identified in the Mount Cap Formation. These confirm the presence of oil-prone source rocks within the Cambrian succession. Where analyzed (in Colville D-45) these strata are barely mature. Although absent from other wells in the vicinity, there is a possibility that thicker source rock intervals at higher levels of maturity occur southeast of the Colville Hills, in the Great Bear Basin or localized in grabens within the Colville Hills area. Oil staining and bleeding of light oil or condensate was observed on most cores taken from the basal Cambrian in this area. Oil staining was also noted in fractured Proterozoic dolomites in Forward et al. Anderson C-51.

Several oil seeps have been noted in Cretaceous sandstones. The bitumen may have originated from Cretaceous shales or possibly Devonian source rocks at greater depths in the basin west of the Colville Hills.

The source of gas in Cambrian reservoirs is problematic. Variation in hydrocarbon composition, the anomalously high nitrogen content in Tweed Lake, and the presence of traces of helium suggests contribution from varied sources, probably in the Precambrian. Long distance up-dip migration of the bulk of the lighter hydrocarbons, possibly from Cambrian or younger source rocks deeper in the basin to the west is also likely.

Potential

The Colville Hills are structurally high and an excellent area for accumulating migrating hydrocarbons from surrounding basins. Better understanding of the timing of migration from these basins and the nature of the migrating hydrocarbons may lead to improved prediction of fills in different categories of structural trap. No significant oil accumulations have been discovered despite a known oil-prone source rock in the Cambrian, associated with reservoir below and seal above.

While the structures are very large in this play, the pay thicknesses in the Mount Clarke are typically thin, less than 10 m (although syn-depositional thickening may locally increase pay thickness). The known resources are spread over a large area and are inadequately delineated. Median aggregate recoverable resources for these pools (ranging from 990.5-5094 x E6 m³; 35-180 bcf) are therefore associated with considerably higher upside figures (2830-8490 x E6 m³; 100-300 bcf at the 25% level). Precambrian dolomites, if fractured within the strands and tensional bulges of the wrench systems, are also potential gas reservoirs.

Several prospects drilled east of the main axis of the Keele Arch were wet and may indicate that gas migration is occurring up-dip from deeper parts of the basin to the west. Several structures on the western flank of the Keele Arch remain untested. Possibilities also exist for stratigraphic and structural/stratigraphic traps involving the pinch-out of Mount Clarke sandstones, possibly against basement highs.

Acknowledgement

A.P. Hamblin (Geological Survey of Canada) kindly permitted reproduction of figures from Hamblin (1990).

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GREAT BEAR BASIN

Age	Early Paleozoic; Cretaceous
Depth to Target Zones	500-1500 m
Maximum Basin Thickness	1000 m Cretaceous
First Discovery	No discoveries
Hydrocarbon Shows	Oil shows in the basal Cretaceous along the Keele Arch (at NSM Mirror Lake N-33 to the west of the basin)
Basin Type	Precambrian to early Paleozoic rifts; early Paleozoic continental margin; Cretaceous foreland basin (shallow eastern margin)
Depositional Setting	Marine/continental
Potential Reservoirs	Cambrian sandstones, lower Paleozoic carbonates, Cretaceous sandstones
Regional Structure	Westward dipping monocline; minor extensional faulting
Seals	Saline River salt, Cretaceous marine shales
Source Rocks	Cambrian: mature oil source rocks, if developed. Cretaceous: possibly immature
Total Number of Wells	16
Seismic Coverage	Sparse regional reconnaissance
Area	approximately 100,000 km ²
Area under Licence	None

(The terrain is low-relief tundra. Winter working conditions are cold, summers buggy. Fort Franklin is the sole population centre in the region. There is a road link to Fort Norman and the Mackenzie River.)

Great Bear Plain (and Lake) occupy a shallow basin between the Franklin Mountains and the Canadian Shield. Cretaceous strata up to 1000 m thick overlie lower Paleozoic and Proterozoic rocks. Paleozoic rocks outcrop along a belt 20 km broad fringing the Canadian Shield. Few wells have been drilled and no discoveries made. There is low to moderate potential for oil and gas pools in this area. Large pools are unlikely, except in stratigraphic traps.

Geological Setting (Fig. 22)

Great Bear Basin is a shallow Cretaceous basin overlying lower Paleozoic strata. The limits of the basin are controlled by gentle upwarp of the underlying Paleozoic strata south of 63°N (across the La Martre Arch) and north of 67°30'N (approaching the Coppermine Arch). To the east, strata outcrop along the edge of the Canadian Shield. To the west, the basin is sharply delineated by the easternmost thrust of the Franklin Mountains, which exposes lower Paleozoic rocks. North of Smith Arm of Great Bear Lake, the margin of the Cretaceous basin runs along the eastern flank of the Keele Arch.

Exploration History (Fig. 23)

Wells have been drilled in three areas of the Great Bear Basin. Most have been drilled in the western half of the basin in anticipation of a thicker sedimentary column. Six wells have been drilled north of the Smith Arm of Great Bear Lake, east of the crest of the Keele Arch; 8 wells between Smith Arm and the Great Bear River, and 10 wells scattered across southern Great Bear Plain south of Great Bear Lake. The target of the northern group has been the Cambrian section, which is gas bearing in Colville Hills. Farther south, the principal objectives have been basal Cretaceous sandstones and underlying Middle Devonian carbonates.

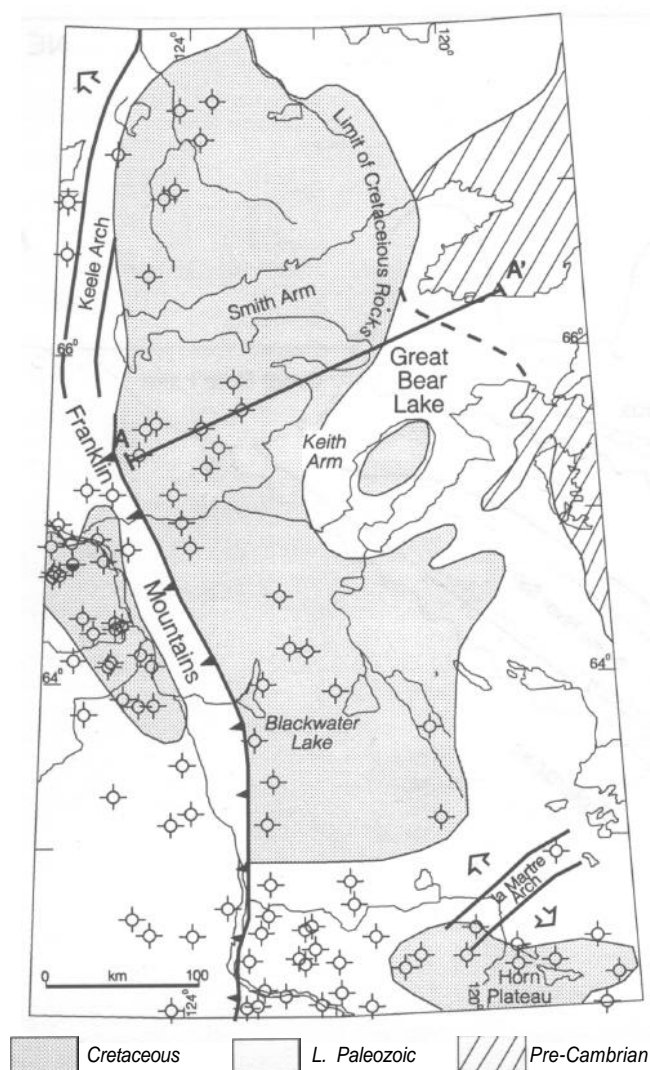


Figure 22. Geological and geographical features, Great Bear Basin.

Stratigraphy (Fig. 24)

The Paleozoic stratigraphy has been described for the Colville Hills in a previous section. Paleozoic strata overlie a thick Proterozoic sedimentary succession. The Cambrian Mount Clarke Formation is thicker than in the Colville Hills. At BP Losh Lake G-22, one of the most easterly wells, Hamblin (1990) reports 65 m of clean sandstone. The Mount Clarke Formation is truncated south of 63°N by the La Martre Falls Formation, a unit of mixed clastic and carbonates equivalent to the Mount Cap and Saline River formations further north. Further south, across the La Martre Arch, the Cambrian is absent. The Middle Devonian Bear Rock and Hume formations are truncated across the Keele Arch and only locally preserved north of the Smith Arm of Great Bear Lake. Ordovician and older strata form the country rock

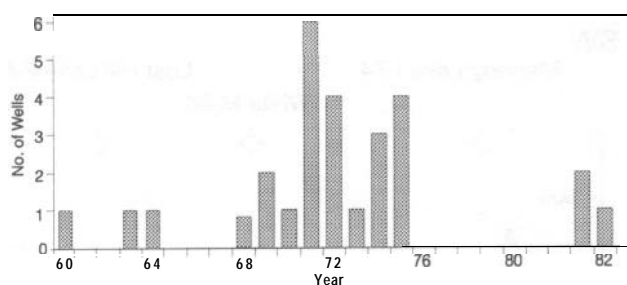


Figure 23. Drilling history, Great Bear Basin.

through most of this northern area. South of Great Bear Lake, Middle Devonian formations subcrop beneath the Cretaceous at shallow depths.

Because of the Keele Arch, the Cretaceous strata of the Great Bear Basin are not readily correlated with the established stratigraphy of the Peel Trough. The succession is of comparable age, ranging from early Albian to Maastrichtian/?Paleocene and the units that have been informally designated in the subsurface by G.K. Williams (1978) may be partially equivalent to the Sans Sault, Arctic Red, Slater River, Little Bear and East Fork formations of the Peel Trough. A conglomeratic basal Cretaceous sandstone is widespread across the Keele Arch and in the Great Bear Basin. This is overlain by a deltaic succession of fine grained sandstones, siltstones and shales.

Potential Reservoirs

The Cambrian Mount Clark and Mount Cap sandstones thicken towards the east. The sandstones are very clean, fine to medium, and locally coarse grained, friable in part, with visual estimates of porosity (in porous streaks) of 15-20%. Minor intergranular porosity has been noted in the lower Paleozoic carbonate sequence.

The basal Cretaceous sandstone is the most porous in the Cretaceous succession. Porosity and permeability measurements on 8 m of core from Losh Lake G-22 indicate an average weighted porosity of 17.5% (with the better sandstones in the 20-23% range) and permeability in the range 150-300 mD. It is a medium to coarse grained quartzose sandstone. The unit averages 25 m in gross thickness, massive in the basal few metres above the unconformity, and overlain by interbedded sandstones and siltstones. Seven drillstem tests have been run across this zone, all have had significant pipe recoveries of mud and salt water. Sandstones higher in the Cretaceous are fine grained and silty with poor porosity.

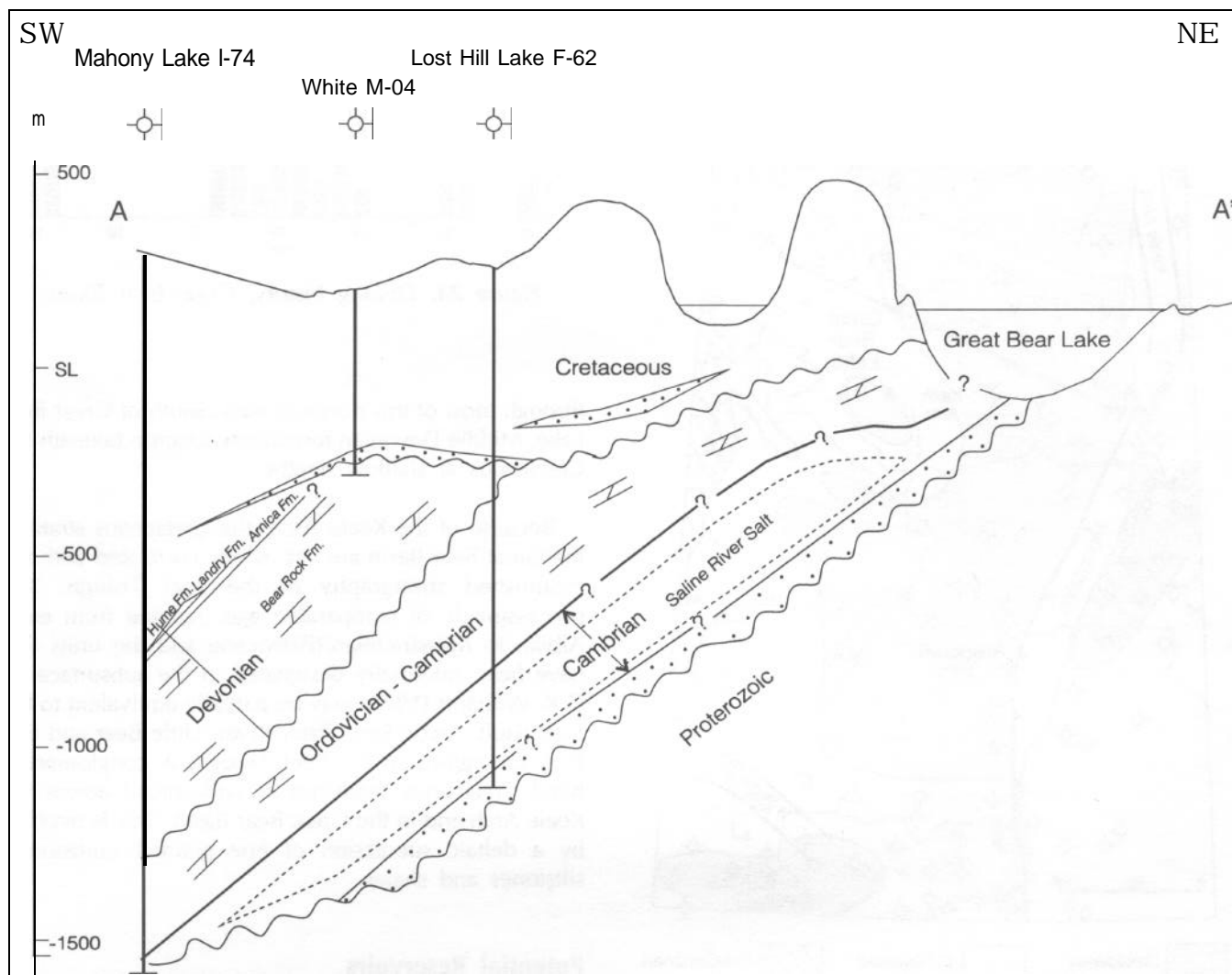


Figure 24. Schematic cross-section, Great Bear Basin.

Structure, Traps and Seal

East of the Keele Arch, geological structure is confined to relatively minor fault displacement along northeast-trending principal fractures and subsidiary orthogonal faults. This fault pattern is inherited from fractures in the underlying Proterozoic. The basal Cambrian play consists of small fault-bounded structures combined with stratigraphic pinch-out of Cambrian sandstones.

Subcrop of Cambrian through Middle Devonian units beneath the basal Cretaceous unconformity provides possibilities for sub-unconformity traps. In the deepest part of the basin, near the Keele Arch, the Hume, Arnica and Bear Rock formations subcrop under the Cretaceous, but seal integrity in the overlying basal Cretaceous is likely to be poor due to the sandy nature of the section.

The basal Cretaceous sandstones vary considerably in thickness. Structural/stratigraphic traps related to the underlying paleo-topography may be anticipated. The streaky nature of porosity in the Cambrian sandstones suggests the possibility of intra-formational up-dip seal.

Source Rocks

Oil-prone source rocks of the Cambrian Mount Cap Formation in the Colville Hills may occur at greater depths (and at higher level of organic maturation) in the Great Bear Basin. It is probable that restricted conditions, favourable to preservation of organic matter, were present throughout much of the early Paleozoic basin, which subsequently accommodated thick salt deposition.

The Upper Cretaceous Slater River source rock of the Mackenzie Plain may extend into the western part of the Cretaceous basin but at an average depth of 600-800 m it is doubtful that it is sufficiently mature to generate oil.

The preferred migration route for gas in the Colville Hills reservoirs calls for regional up-dip migration from deeper parts of the basin to the west. The Great Bear Basin is isolated from this migration path. However, there remains the possibility that mature gas source rocks occur in the Proterozoic section.

Potential

The presence of oil-prone Cambrian source rocks (suggested by wells in the Colville Hills) at somewhat greater depth (and maturity) than in the Colville Hills, combined with greater thickness of basal Cambrian sandstones of the Mount Clarke Formation favour a possible oil play in the Great Bear Basin. The presence and volumetric significance of a source rock in the Cambrian is a significant risk in this play. Exposure to infiltration of the reservoir by meteoric waters becomes an increasing risk towards the eastern outcrop zone, which largely lies beneath Great Bear Lake.

East of the Keele Arch, potential reservoir in the Cretaceous is limited to the basal Cretaceous sandstone. The reservoir is generally thin but with good porosity and permeability. The play has some potential for small oil discoveries, with presence and maturity of source rock a major risk.

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ANDERSON AND HORTON PLAINS

Age	Cretaceous Anderson Basin lying over Devonian and older platform strata
Depth to Target Zones	500-3000 m
First Discovery	No discoveries
Basin Type	Paleozoic platform. Cretaceous interior basin
Depositional Setting	Marine shelf
Potential Reservoirs	Platform carbonates, reefs?, Imperial Formation sandstones, basal Cretaceous sandstones
Regional Structure	Westward dipping monocline: faulted along Eskimo Lakes Arch to the northwest
Seals	Cretaceous marine shales
Source Rocks	Canol shales
Total Number of Wells	9 Anderson Basin; 12 Carnwarth Platform
Seismic Coverage	Sparse, reconnaissance
Area under Licence	None

(A remote region with access possible from the Mackenzie River, from Tuktoyaktuk via Liverpool Bay, and from Paulatuk on Darnely Bay. Low relief, muskeg.)

The Anderson and Horton plains lie north and east of the Mackenzie River, extending to the shores of Liverpool Bay and Amundsen Gulf. Drilling objectives include the equivalent lower Paleozoic succession present in the Colville Hills (but less structured), Upper Devonian imperial formation, and Cretaceous sandstones in the shallow Anderson Basin. Surface oil shows occur in Cretaceous sandstones (at Rond Lake) and a gas show in sandstones at the Cretaceous/Devonian unconformity (at Russell H-23). Well and seismic control is sparse. No discoveries have been made.

Geological Setting (Fig. 25)

Cretaceous sediments of the Anderson Basin fill a crustal downwarp between the Carnwarth Platform to the southeast and the Eskimo Lakes Arch to the northwest. The northwestern margin is delineated by faults flanking the Eskimo Lakes Arch. The eastern flank of the basin rises gently to outcrop along the flank of the Coppermine Arch.

Sadene D-02, were spudded in the Imperial Formation. Twelve wells have been drilled to Devonian targets in southern Anderson Plain. A cluster of wells at Rond Lake were drilled in the hope of discovering a Devonian accumulation underlying a surface oil seep in Cretaceous sandstones.

There is sparse reconnaissance seismic in the region with large gaps evident in the coverage.

Exploration History

Seven wells have been drilled along the southern flank of the Eskimo Lakes Arch. These penetrate Cretaceous strata to depths of up to 2000 m. They overlie Imperial Formation sandstones and shales. Two wells have been drilled on the Cape Bathurst Peninsula.

Only four wells have been drilled in central Anderson Plain. All, with the exception of Mobil Gulf

Stratigraphy (Fig. 26)

Cretaceous strata unconformably overlie the Upper Devonian Imperial Formation in the western part of the region and progressively older units farther east, across the Carnwarth Platform. Upper Cretaceous strata outcrop on the Bathurst Peninsula (notably in the Smoking Hills along the eastern coast of Cape Bathurst). More extensive outcrops of the Langton Bay Formation and Albian Horton River formations occur to the south

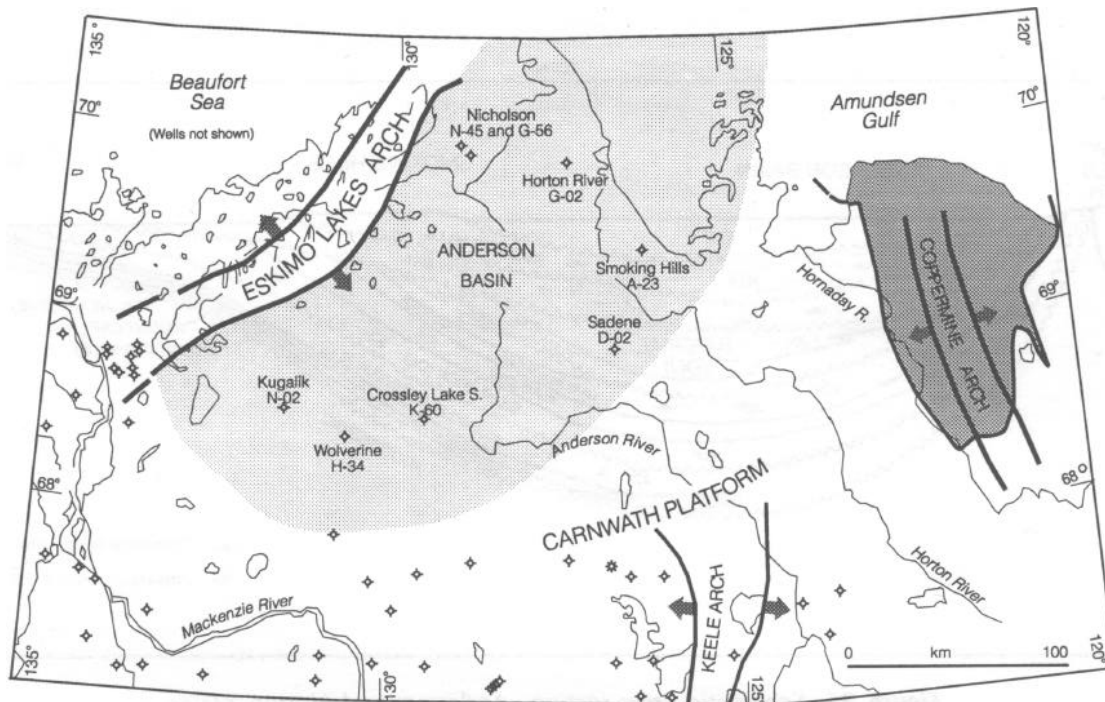


Figure 25. Geological and geographical features, and well locations, Anderson and Horton plains.

and east. East of 125°W, Cretaceous strata occur as scattered outliers and the country rock comprises Cambrian to Ordovician strata of the Mount Clark, Mount Cap, Saline River, Franklin Mountain, Mount Kindle, Bear Rock and Hume formations. Lower Paleozoic rocks are truncated at the edge of the Canadian Shield and along the flanks of the Coppermine Arch.

Proterozoic sedimentary rocks of the Shaler Group are exposed across the Coppermine Arch.

Potential Reservoirs

The Cambrian Mount Clarke sandstones are well developed in outcrop close to the Coppermine Arch. These are potential reservoirs beneath Horton Plain but become increasingly fine grained with poorer reservoir potential to the west.

The lower Paleozoic carbonate succession subcrops at the base of the Cretaceous. Development of secondary porosity is probable along the strike of susceptible carbonate facies. Potential for development of reefs appears limited. Older carbonate units demonstrate some porosity development with bitumen reported in vugs. However, reservoir breaching is likely to have flushed or biodegraded most oil.

Sandstones in the Imperial Formation and Cretaceous strata are potential reservoir rocks although thick potential reservoir intervals have not been discovered and porosity is generally low.

Source Rocks

Excellent oil-prone source rocks are present in the Upper Cretaceous section but are immature. The bocannes (outcrops of burning bituminous shale) evident in the Smoking Hills are the result of oxidation of pyrite and/or organic matter in the bituminous Smoking Hills Formation. Vitrinite reflectance values of the shales away from the bocannes fall well below the oil window (Mathews and Bustin, 1984).

Organic matter in the Imperial Formation is terrestrially derived with maturity falling within the oil window (thermal alteration indices of 2 +). The Imperial is gas prone and is the most likely source of the gas show at Imp Cigol Russell H-23.

Potential

In the eastern part of the region, the Cambrian section contains good reservoir sandstones and a potentially effective regional seal. Principal risks are lack of an

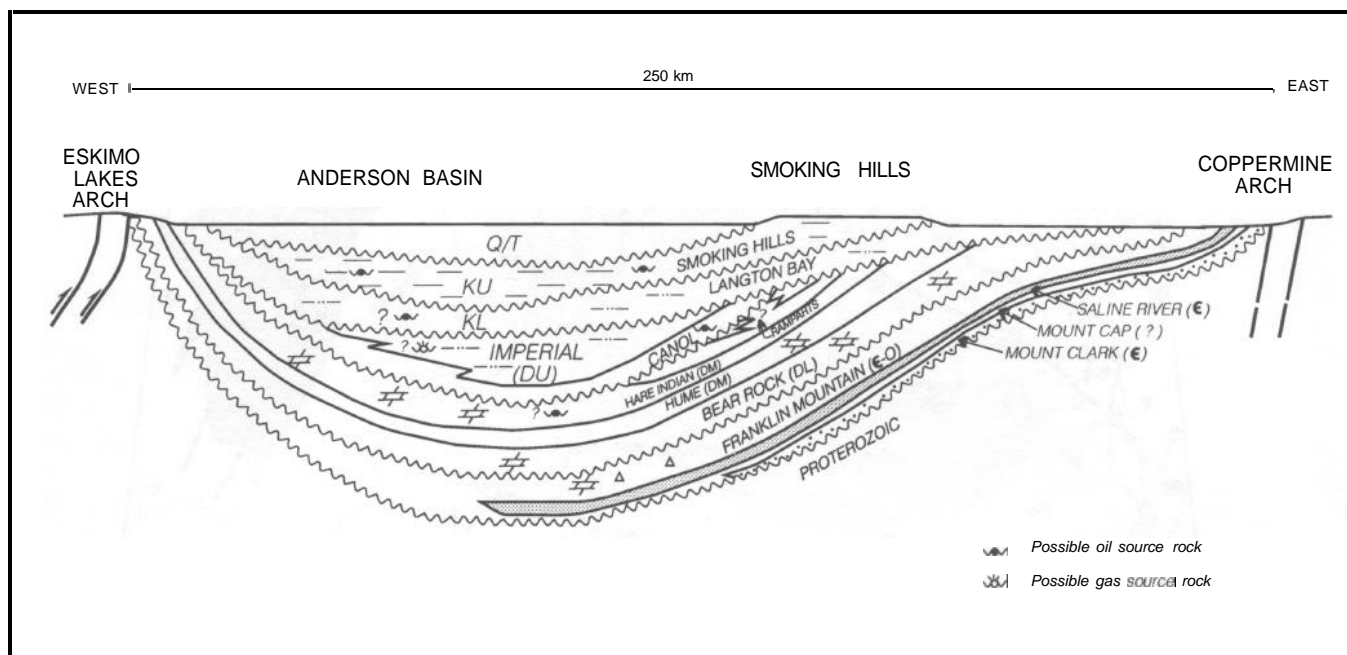


Figure 26. Schematic cross-section, Anderson and Horton plains.

effective source rock and reservoir invasion close to the outcrop zone.

The northward trend of Devonian and older units beneath the pre-Cretaceous unconformity defines the eastward limits of potential targets and fairways for sub-unconformity traps across the Carnwarth Platform. Perhaps most significant is the Canal/Ramparts subcrop, which strikes due north close to longitude 130°W. These units are proven oil source rocks and reservoirs farther south. Principal risks are reservoir development and reservoir breaching.

Sandstones in the shale-dominant Imperial Formation are potential reservoirs in the Anderson Basin. However, the formation consists of thin interbedded sandstones, siltstones and some conglomerates, and potential pay is likely to be thin and of indifferent quality. Across the Carnwarth Platform, Cretaceous sandstones are close to the surface and contain biodegraded oil. However, some Cretaceous potential

exists in the Anderson Basin where the Lower Cretaceous section underlies Upper Cretaceous shales, which form an effective top seal for hydrocarbons. Although most marine shelf sands in the Anderson Basin are thin and have poor reservoir potential, there exists the possibility of an incised drainage system on the sub-Cretaceous unconformity. If present it could contain alluvial sandstones with good reservoir potential.

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CHAPTER 3 – NORTHERN YUKON

EAGLE PLAIN BASIN

Age	Paleozoic to Cretaceous, with Quaternary cover
Depth to Target Zones	650-2800 m
Maximum Basin Thickness	5800 m
Hydrocarbon Shows	Middle Devonian to Lower Cretaceous strata; in several wells
First Discovery	1960 (Western Minerals Chance L-08; gas and oil)
Discovered Resources	Gas: 1760-3620 x E6 m ³ (90 % range); 2524 x E6 m ³ (at 50%) Oil: 1.34-2.85 x E6 m ³ (90%, range); 1.86 x E6 m ³ (at 50%)
Production	No production to date
Basin Type	Shallow marine shelf (Paleozoic to early Mesozoic); intermontane compressional (Cretaceous to Recent)
Depositional Setting	Shallow-water carbonate and clastic shelf
Reservoirs	Carbonate reefal mounds and facies fronts; fractured carbonates; unconformity traps and discontinuous marine clastic lenses
Regional Structure	Long wavelength folds at surface; detachments with thrust folds within deeper strata; contraction and minor relaxation faulting
Seals	Marine shales and tight carbonates
Source Rocks	Shales and organic-rich carbonates
Depth to Oil/Gas Window ...	2300 m
Total Number of Wells	36 (31 dry; 1 oil; 2 gas; 2 gas and oil); 2 wells post-1980
Seismic Coverage	9952 km; 790 km post-1980
Pipelines	None
Area	24,060 km ²
Area under Licence	8900 ha (0.4% of basin, in 3 Significant Discovery Licences)

(Low rolling hills, elevation between 400 and 800 m. Lightly forested in southern Eagle Plain thinning to the north. Higher and northern areas are mostly tundra. Good access from the Dempster Highway, which is open most of the year. Population/service centres on the Dempster Highway, at Inuvik (250 km) and at Dawson City (also 250 km)

The Eagle Plain Basin is an under-explored basin with proven oil and gas potential. Clastic reservoir rocks of Mississippian to Permian and Early Cretaceous age host the discovered pools in combined structural and unconformity traps in the southern Eagle Plain close to the Dempster highway. High potential exists for additional discoveries of oil and gas pools of small to moderate size. There is additional potential for discoveries in northern Eagle Plain along the transition between Paleozoic platform carbonates and basinal shales.

Geological Setting (Fig. 27)

The Eagle Plain Basin is an intermontane compressional basin straddling the Arctic Circle in the Yukon Territory, 2500 km north of Calgary and 80 km east of the Yukon-Alaska border. The basin formed during the Laramide orogeny when Palaeozoic and Cretaceous

shallow-water shelf sediments (clastics and carbonates) were folded and faulted. The preserved extent of the Mesozoic sediments outlines the present day limits of the basin, which is surrounded by outcrop belts in the Richardson Mountains to the east and north, the Ogilvie Mountains to the south and west and the Dave Lord Range of the Ogilvie Mountains to the north.

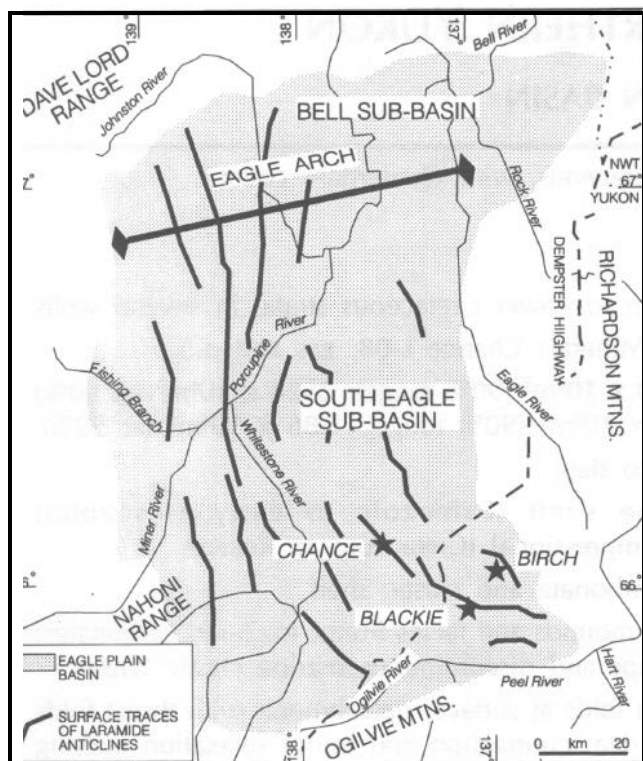


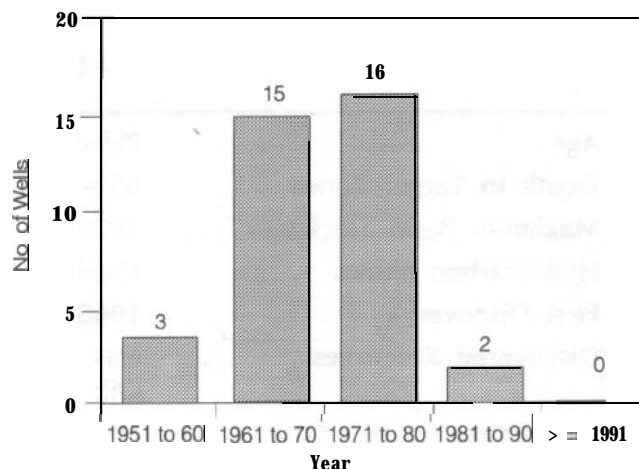
Figure 27. Major structures, well locations and sub-basins, Eagle Plain Basin.

The basin is bisected by the Eagle Arch, a northeast-southwest aligned subsurface ridge that separates the shallower northern portion of the basin - the Bell subbasin - from the southern part of Eagle Plain Basin, which contains a thicker and more complete stratigraphic section.

Exploration History (Figs. 28, 29)

Petroleum exploration started in the late 1950s with the drilling of the Peel Plateau Eagle Plain Y.T. No. 1 N-49 well in the north-central part of the basin. The N-49 well was drilled on a surface anticline to 2923 m, terminating in Cambrian-Ordovician shales and carbonates without encountering hydrocarbons. The second prospect tested a surface anticline in the southern part of the basin, and resulted in the first discovery in the basin at Western Minerals Chance Y.T. No. 1 L-08 in 1960. The L-08 well was drilled to 2636 m, terminating in Mississippian carbonates and encountered hydrocarbons in six separate zones. Since the first discovery, additional exploratory and delineation wells have been drilled. Two additional significant hydrocarbon discoveries have been made at the Blackie (1964) and Birch (1965) fields. Hydrocarbons have been discovered in a total of nine separate zones with potential in two deeper horizons indicated by shows.

EAGLE PLAIN Y.T. DRILLING ACTIVITY



EAGLE PLAIN Y.T. REFLECTION SEISMIC ACTIVITY

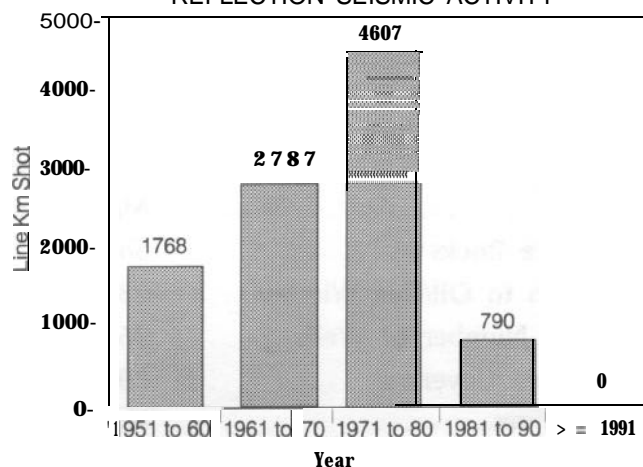


Figure 28. Drilling and seismic history, Eagle Plain area.

Seismic lines totalling 9952 km have been shot in the basin, about half this total since 1970. By far the largest regional program was shot by Chevron in 1971. There is a concentration of seismic coverage in the vicinity of the three discovered fields.

Half the wells in the basin were drilled after 1970 with the most recent drilling in 1985 (Exco West Parkin D-54 and Exco North Chance D-22). The drilling density is 1 well per 745 km² but is concentrated in the southern portion of the basin. However, wells have been drilled in all quarters of the basin and provide useful stratigraphic control.

Stratigraphy (Fig. 30)

Within the Eagle Plain Basin, strata of Precambrian to Cretaceous age are preserved along with a thin cover of

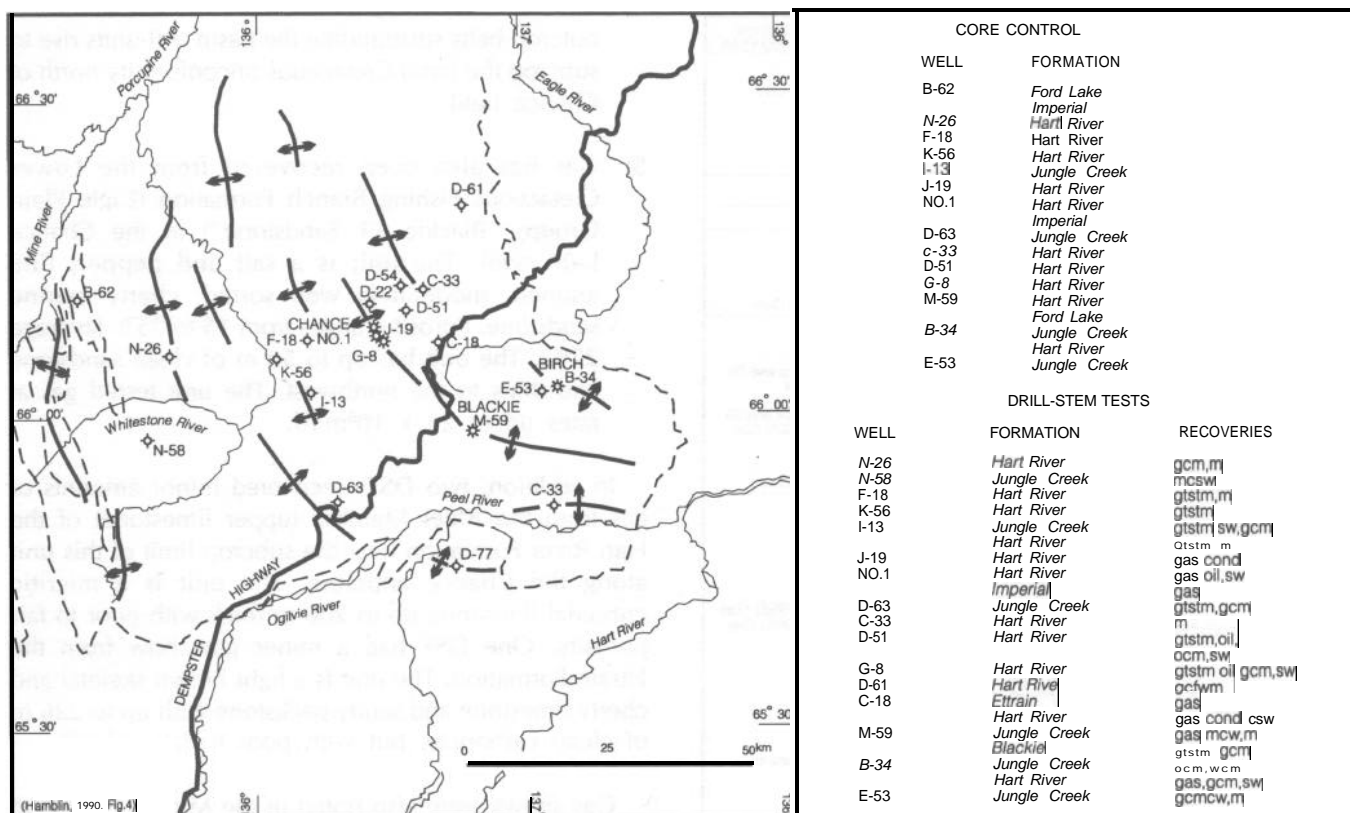


Figure 29. Well locations and structures, southern Eagle Plain.

Quaternary deposits. Triassic and Tertiary strata are absent. Carbonates dominate the Ordovician to the Middle Devonian, with mixed carbonate/clastic lithologies typical of the Upper Devonian and Carboniferous. The Permian strata of the basin are predominantly clastic as is the Mesozoic section. Mesozoic deposition was characterised by lateral facies transitions. Three main unconformities are present in the section. The schematic cross-section shows the stratigraphic relationships and trap styles within the basin.

Two important stratigraphic controls on hydrocarbon prospectivity are: a) the sub-Cretaceous unconformity, which defines the limits of plays represented by subcropping Carboniferous to Permian strata in southern Eagle Plain; b) the Lower to Middle Devonian carbonate to shale facies transitions in the Bell subbasin.

Potential Reservoirs (Fig. 31)

Hydrocarbons have been tested from five horizons within upper Paleozoic and Lower Cretaceous strata:

- 1) Western Minerals et al. Chance No. 1 L-08, tested gas at good flow rates ($225 \times 10^3 \text{ m}^3/\text{d}$) from a 3.6 m brecciated, cherty, pebbly sandstone with 16% porosity – the Tuttle Sandstone.
- 2) Gas and oil were recovered from the Canoe River Member (lower limestone) of the Hart River Formation in Chance field. The Canoe River Member consists of thinly bedded, micritic, crinoidal limestone with chert, dolomite and shale interbeds. Five hundred metres of clean carbonate are present with porosity up to 13%. Within the Chance field two pools have been found (one oil and one gas pool at Chance L-08, and one gas pool at Chance G-19). The unit has tested gas at rates up to $283 \times 10^3 \text{ m}^3/\text{d}$ and has recovered 290 m of oil.
- 3) Gas and oil also have been recovered from the Chance Sandstone Member of the Hart River Formation in the vicinity of Chance field. The Chance Sandstone Member consists of fine to medium grained, moderately to well sorted, salt and pepper sandstone with porosity ranging from 5 to 22% (average 14%) and permeability varying from 100 to 500 mD. Gross thickness of sandstone

AGE	SYSTEM	FORMATION AND LITHOLOGY	HYDROCARBON SHOWS OR DISCOVERIES, WELLS AND YEAR
CRETACEOUS	Upper	Eagle Plain Group	Chance L-08 (1960) Gas
	Lower	Whitestone River Fm.	
JURASSIC			
TRIASSIC			
PERMIAN	Upper		
	Lower	Jungle Creek Fm.	Blackie M-59 (1964) Gas
CARBONIFEROUS	Upper	Ettrair Fm.	
		Blackie Fm.	
		Hart R. Fm.	Chance L-08 (1960) Gas and Oil Chance G-08 (1965) Oil Birch B-34 (1965) Gas Chance G-19 (1968) Gas and Oil South Chance G-19 (1968) Gas
	Lower	Alder Mbr. Chance Mbr. Ford Lake Fm.	
DEVONIAN	Upper	Tuttle Sand	Chance I-08 (1960) Gas
		Imperial Fm.	
		Canoe Fm.	
	Middle	Ogilvie Fm.	Peel Plateau N-49 (1958) Gas South Tuttle N-05 (1965) Gas
DEVONIAN	Lower	Prong's Ck. Fm.	
		Gossage Fm.	
DEVONIAN		Road River Fm.	
DEVONIAN		Ronning Gr.	
CAMBRIAN			
PRECAMBRIAN		Granites and Metamorphic Rocks	

Figure 30. Table of formations, Eagle Plain Basin.

at Chance amounts to 130 m. Within the Chance field six Chance Sandstone pools have been found (one oil and three gas pools defined in Chance G-19, L-08 and G-08, and one oil pool at Chance G-08). An additional gas pool in the Chance Sandstone was discovered at Birch B-34. The unit tested gas at rates up to $230 \times 10^3 \text{ m}^3/\text{d}$ with 610 m pipe recovery of oil and condensate.

- Gas has also been recovered from the Lower Permian Jungle Creek Formation in the Blackie field. The unit is a medium to coarse grained, poorly sorted, conglomeratic sandstone, 3 to 30 m thick. Porosity ranges from 5 to 20% (average 15%) and permeability from 100 to 200 mD. Up to 166 m of clean sandstone are present. The unit tested gas at rates up to $99 \times 10^3 \text{ m}^3/\text{d}$ at Blackie. Possible oil potential is indicated by an oil cut mud DST recovery from the Jungle Creek in Birch B-34, to the north and east of the Blackie field.

All the upper Paleozoic reservoirs thin to the south and, with the exception of the Tuttle Sandstone and the Hart River Formation, are not developed in the

outcrop belts surrounding the basin. All units rise to subcrop the basal Cretaceous unconformity north of Chance field.

- Gas has also been recovered from the Lower Cretaceous Fishing Branch Formation (Eagle Plain Group; "Blackie K1 Sandstone") in the Chance L-08 well. The unit is a salt and pepper, fine grained, moderately well sorted, cherty marine sandstone. Porosity ranges from 15 to 25% (average 22%). The unit has up to 50 m of clean sandstone and thins to the northwest. The unit tested gas at rates up to $23 \times 10^3 \text{ m}^3/\text{d}$.

In addition, two DSTs recovered minor amounts of gas from the Alder Member (upper limestone) of the Hart River Formation near the subcrop limit of this unit along the Chance anticline. The unit is a micritic crinoidal limestone up to 200 m thick with poor to fair porosity. One DST had a minor gas show from the Ettrair Formation. The unit is a light brown skeletal and cherty limestone and sandy packstone with up to 226 m of clean carbonate, but with poor to fair porosity.

Gas shows were also noted in the Middle Devonian Ogilvie Formation (Peel Plateau N-49 and South Tuttle N-05) and in the Lower Devonian Gossage Formation (South Tuttle N-05). Both these thick carbonate unit are potential reservoir rocks.

Structure, Traps and Seal

Parallel, northward-striking anticlines and synclines are the principal surface structures. Thrust faults parallel to the surface structures are present in the subsurface. These faults may or may not have surface expression with the limited thrust-ramping concentrated at the basal Cretaceous unconformity. Trapping configurations are multiplied by permutations of several potential reservoirs subcropping beneath unconformities along the plunge of the anticlines. In addition, several possibilities for stratigraphic traps are present.

Five types of hydrocarbon traps have been identified within the basin: 1) Laramide folds (Jungle Creek in Blackie M-59 and Fishing Branch sandstone in Chance L-08); 2) combined structural-stratigraphic-unconformity traps beneath Lower Cretaceous shale (Chance sandstones in Chance L-08); 3) reverse dip stratigraphic facies changes (gas show in South Chance D-63); 4) pinch-out of discontinuous sandstone lenses (basal Chance sandstones), and 5) carbonate to shale facies transitions (Canoe River limestones in Chance M-08 and possible Ogilvie/Gossage traps as demonstrated by the gas shows in South Tuttle N-05).

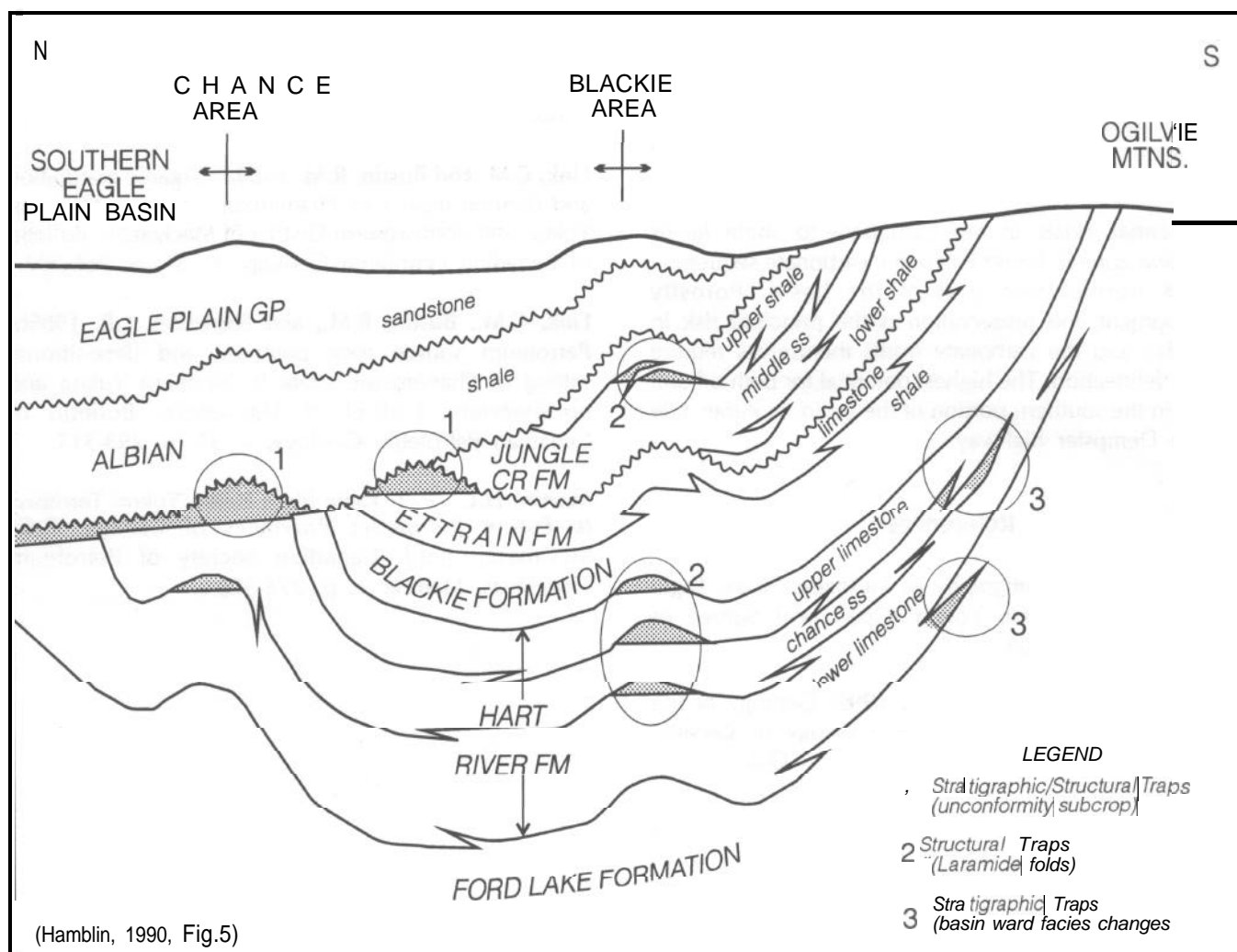


Figure 37. Schematic cross-section and potential reservoirs and traps, Eagle Plain Basin.

Intraformational shale forms local seals for the Carboniferous and Cretaceous reservoirs while facies changes from carbonate to shale form lateral seals for lower Palaeozoic reservoirs. The Lower Cretaceous Whitestone River Formation is a regional top seal for reservoirs truncated by the sub-Cretaceous unconformity. The Canol and Prongs Creek shales form regional top seals for the Ogilvie and Gossage carbonates.

Source Rocks

Five source rocks have been identified: 1) the lower Palaeozoic Prongs Creek Formation (no maturity information); 2) the lower Palaeozoic Canol Formation (Type II and III, TOC up to 9%; currently overmature for oil); 3) the upper Palaeozoic Ford Lake Formation (Type II and III, TOC up to 4%; currently mature for oil and the most likely source of the Chance oil); 4) the upper

Carboniferous shales and organic-rich carbonates of the Blackie Formation (Type II and III, TOC up to 5%; marginally mature for oil), and 5) the Albian shales of the Whitestone River Formation (Type II and III, marginally mature). Minor source rock potential may exist in shales of the Imperial (Type III, TOC less than 1 % and Jungle Creek formations (no maturity data).

Gas discovered to date has been 75 to 85% methane with minor amounts of CO₂, N₂ and liquids. Oil discovered to date has been a low sulphur, 29° to 37° API crude.

Potential

Potential is high for further discoveries in upper Palaeozoic stratigraphic and sub-unconformity traps along the crest of folds in southern Eagle Plain. In this region several subsurface thrust-folds remain to be

delineated and further possibilities exist down the plunge of already drilled structures. Also, but with greater risk, there are structurally reversed basinward facies changes within the Hart River and Jungle Creek formations between the Blackie area and the outcrop belts in the Ogilvie Mountains.

Potential exists in the carbonate to shale facies transition zone in lower Paleozoic carbonate sequences in the northeastern part of the basin. Porosity development and preservation is the principal risk in this play and the carbonate fronts themselves require better delineation. The highest potential for both oil and gas is in the southern portion of the basin on either side of the Dempster highway.

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WHITEHORSE BASIN

Age	Late Triassic to Early Cretaceous
Depth to Target Zones	Surface to ?3000 m
Maximum Basin Thickness	?5000 m
First Discovery	None
Basin Type	Back-arc basin accreted to craton margin
Depositional Setting	Marine, deltaic to alluvial
Potential Reservoirs	Triassic reefs, Jurassic sandstones
Regional Structure	Tight folds; intensely deformed and intruded to southwest
Seals	Marine shales
Source Rocks	Jurassic Laberge and Tantallus formations
Depth to Oil Window	Surface
Total Number of Wells	None
Seismic Coverage	None
Area	20,000 km ²
Area under Licence	None

(The most prospective parts of the basin are close to highways with easy access to population and service centres. The terrane is rugged but accessible with limited tree cover. Exploration conditions compare with the foothills of northeast British Columbia.)

The Whitehorse Basin contains variably preserved Mesozoic strata in a highly structured intermontane setting. Reefs and associated carbonates, and deltaic sandstones have potential for porosity development in the subsurface; shales and fine grained volcaniclastic rocks have sealing potential, and several potential source rocks have been identified. Surface anticlines are possible drilling targets, although the high density of faulting complicates structural definition in the subsurface. Maturity levels are high within the axial part of the basin, but drop to within the gas window towards the flanks of the basin. Oil potential is minor.

Geological Setting (Fig. 32)

The Whitehorse Basin lies within the Intermontane Belt of the North American Cordillera. The basin fill consists of Mesozoic volcanic and sedimentary rocks of an allochthonous terrane - Stikinia - which attached to the margin of ancient North America during the mid-Jurassic. The basin is sandwiched between igneous rocks of the older Omineca to the east and the younger Coastal Plutonic Belt to the west.

Sediments of the basin were deposited in a back-arc setting with the volcanic island arc to the southwest. Thick sequences of Triassic volcanic and volcaniclastic rocks were deposited close to the emergent arc, yet areas of the basin were sufficiently remote from clastic input or favourably situated in the oceanic circulation

to favour the growth of reefs. In the early Jurassic, the emplacement and un-roofing of granitic plutons accompanied accelerated subsidence in the basin and the deposition of thick sequences of fan-conglomerates and volcaniclastics.

Uplift and compression at the beginning of the Cretaceous ended sediment accumulation in the basin. Paleomagnetic evidence suggests subsequent northward movement of the Stikine terrane relative to the North American continent in the Late Cretaceous and early Tertiary (although estimates of the amount of northward displacement are poorly constrained by the data). Shear stress generated during displacement of the basin caused extensive jointing and faulting, and much of the western and southwestern basin suffered intrusion by plutonic rocks over this period.

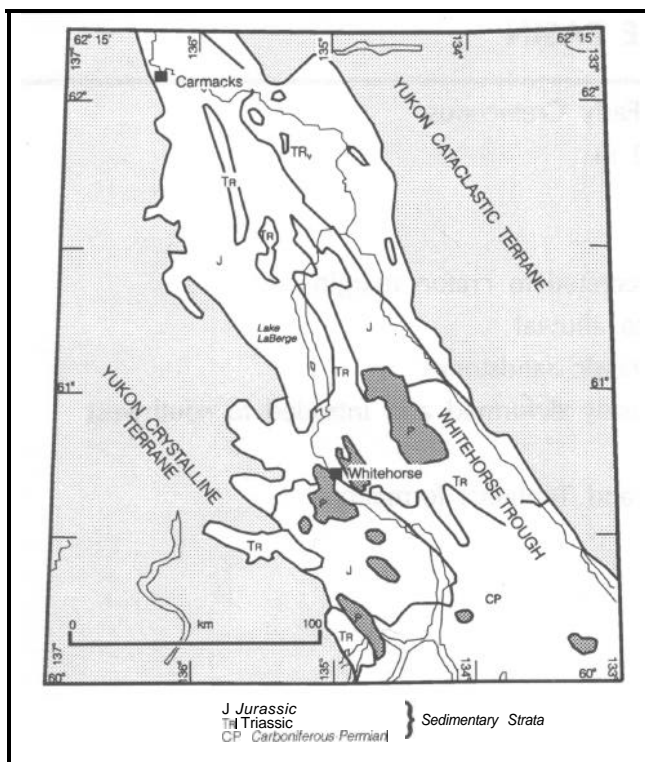


Figure 32. Simplified geological map of the Whitehorse Basin.

Exploration History

Hydrocarbon exploration in the basin has been limited to field geology: most of the stratigraphic section is well exposed within the limits of the basin and surface studies provide a good notion of units to be expected in the subsurface. No seismic lines have been shot nor wells drilled in the basin.

Several coal deposits are known from the basin, principally in the Upper Jurassic and Lower Cretaceous Tantalus Formation. Coals are generally of limited extent as a result of restricted deposition. Rank is variable: one deposit (at Braeburn) is an anthracite. Coals are generally bituminous, of moderate to high volatility. Some deposits may have potential for coal bed methane development, although direct utilization of the coal itself has been the preferred option for local energy sources to date.

Stratigraphy (Fig. 33)

As much as 5 km of sedimentary strata may have been deposited in the basin, but the degree of preservation of this original fill is highly variable. The basin is floored by metasediments of the Yukon Group (Precambrian

	AGE	FORMATION	LITHOLOGY
CRETACEOUS	NOECOMIAN	TANTALUS FM.	Arkose, siltstone, argillite, coal, conglomerate
JURASSIC		LABERGE GROUP	<p>TANGLEFOOT FM. Arkosic sandstone</p> <p>---Tufts---</p> <p>CONGLOMERATE FM.</p> <p>RICHTHOFFEN FM. Shale, Arkosic sandstone</p>
TRIASSIC	NORIUM	LEWES RIVER GROUP	MANDANA MBR. Grey, green and red greywacke and pebble conglomerate
			HANCOCK MBR. Limestone
	KARNIUM		CASCA MBR. shale, greywacke, limestone
		POVOAS FM.	Volcanic breccia, chlorite - amphibole schist
PERMIAN		TAKU GROUP	Limestone, limestone breccia, chert, greenstone, and (?) pyroclastic rocks

Figure 33. Table of formations, Whitehorse Basin.

and younger). These are overlain by upper Paleozoic (Permian and ?Pennsylvanian) volcanic rocks and limestones of the Taku Group. The Mesozoic stratigraphy of the basin comprises three main divisions - the Lewes River Group (Upper Triassic) the younger Laberge group (Jurassic), and the Upper Jurassic to Lower Cretaceous Tantalus Formation. No type sections have been defined for these units and their boundaries are ill defined. The Lewes and Laberge groups do not appear to be separated by any major discontinuity.

- 1) Lewes River Group. The Povoas Formation at the base of the group comprises basalts and volcanic breccia, metamorphosed to schist in the Carmacks area. The volcanic rocks are overlain by the Aksala Formation, divided into three members. In the Laberge area, the Casca Member consists of calcareous greywacke and sandstone, interbedded bioclastic limestone and argillaceous limestone, and minor conglomerate and agglomerate. The Hancock Member is a carbonate unit comprising thick limestones and minor argillaceous limestones. Reef growth occurred where substrate and turbidity permitted. Reefs may be stacked or merge laterally to cause major variations in thickness. The northeastern side of the reefs is typically steep and faced by greywacke and limestone boulders from the reef margin. The southwestern margin of the reefs grade into bioclastic sands deposited in

shallow-water lagoons, and farther west, closer to the shores of the island arc, into, quartzose sandstones. The Mandanna Member consists of red greywacke and pebble conglomerate. The unit may represent shallowing in the basin and exposure of reef tops.

The Lewes River Group outcrops along the trend of the Povoas Anticline east of Lake Laberge and in a broad band crossing the central basin at the latitude of Whitehorse. It is presumably present in the subsurface beneath the outcrop of younger Laberge strata. Over 2000 m of strata are present.

- 2) The Laberge Group represents a major progradation of clastic material from the developing island arc, which inhibited further reef development in the basin. Deep-water silty shales with minor conglomerate, and more proximal arkosic sandstones of the Richthofen Formation are overlain by thick conglomerates of the Conglomerate Formation, tuffs of the Nordenskold Formation, and coarse grained arkosic sandstones of the Tanglefoot Formation. The Laberge Group outcrops extensively to the north and west of Lake Laberge and southwest of Whitehorse. Over 2000 m of strata are present.
- 3) The Tantalus Formation overlies the Laberge Group above an angular unconformity. Its chert-rich conglomerates and sandstones are distinctly different from the granite-derived clasts of the underlying strata. Tantalus sediments were deposited on a broad coastal plain, possibly within an enclosed basin removed from marine influence. Rocks are conglomeratic sandstones, deltaic sandstones and coals, which may have been derived from both eastern and western margins of the basin. The Tantalus is preserved as small outliers in the northern part of the basin, with the most extensive outcrop in the Carmacks area. About 750 m of strata are present.

Potential Reservoirs

- 1) Sandstones and conglomeratic sandstones of the Laberge Group. The proximal facies of the Richthofen, the Conglomerate and Tanglefoot formations have potential for subsurface porosity as a result of feldspar dissolution.
- 2) Reef carbonates and associated clastic facies of the Lewes River Group. The well exposed reef complex at Lime Peak (east of Lake Laberge) is 250 m thick and has been mapped laterally for 3 km. The reefs,

inter-reef limestone conglomerates and carbonate sandstones, have the potential to develop porosity in the subsurface. Laterally equivalent carbonate and relatively mature quartzo-feldspathic sandstones are additional potential reservoirs and may be more extensive in the subsurface than the reefs themselves.

Porosity and permeability may be enhanced through fracturing in all of these units.

Structure, Traps and Seal

The principal trend of fold axes and faults is northwesterly, parallel to the basin-bounding faults and at right angles to the direction of principal compression. However, post-compressional shear has imposed high densities of subsidiary faults at diverse orientations on most of the original structures.

Surface mapping has delineated a series of faulted anticlines within the basin. Mesozoic cover is deeply truncated across the more prominent anticlines and there is high risk of reservoir breaching, particularly in the Laberge Group. The deeper structure of the basin can only be inferred: however, it is likely that structural traps with no surface expression exist in the subsurface.

Reservoir properties may be enhanced by fracturing but the integrity of potential seals is likely to have been lessened. The Richthofen shales may form an effective seal above the Lewes River Group. Seals are likely to be scarce in the proximal sandstone facies that characterizes the Laberge Group in the southwestern part of the basin. Fine grained volcanoclastic rocks are potential seals and recur throughout the Mesozoic succession. In general there is a high risk of seal failure in this highly structured and repeatedly stressed basin.

Source Rocks

A number of oil seeps have been reported from the region. Limited sampling suggests that these were spills of refined products and not geological oil. Surface gas seeps have also been inferred from the reports of "fireballs" ignited by the hot exhausts of passing traffic. A biogenic origin for the gas seems the most probable explanation for this phenomenon.

Templeman-Kluit (1978) noted that the back-reef facies of the Lewes River Group are locally bituminous and may be potential sources of hydrocarbon accumulations in the associated reefs and shoal clastic facies, given a suitable cap rock. Limited geochemical

sampling and analysis of shales within the major stratigraphic units of the basin have shown the Aksala Formation of the Lewes River Group to be lean in organic carbon and a fair source of gas at best. The Jurassic/Cretaceous Tantalus Formation has Total Organic Carbon content (TOC) values in excess of 1 % in the northeastern and southwestern parts of the Whitehorse basin. Both oil and gas potential is possible. The Jurassic Richthofen Formation has TOC over 1 % in the western part of the basin but with gas potential only. All potential source rocks appear to be over-mature along the central axis of the basin (reflecting deepest burial?) but within the gas generation window towards the flanks of the basin. The Tantalus Formation at surface falls within the oil window on the basis of limited vitrinite reflectance measurements.

Potential

The basin has low to moderate potential for conventional gas accumulations, and exploration in this highly structured area with discontinuous and unproven reservoirs must be considered high risk. Surface anticlines are obvious targets for a first phase of drilling where potential reservoir units have not been breached. Oil potential appears to be minor in the absence of regionally extensive oil-prone source rocks and the high

levels of maturity. Coal seams offer some possibility for exploitation of coal-bed methane.

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KANDIK BASIN

Age	Palaeozoic to Cretaceous; Quaternary cover
Depth to Target Zones	2500-4500 m
Maximum Basin Thickness	Up to 5500 m of Mesozoic rocks
Hydrocarbon Shows	Surface: dead oil in Triassic shales and Paleozoic limestones Subsurface: oil staining and minor gas shows, bitumen
First Discovery	None
Basin Type	Cordilleran: autochthonous shallow-water marine shelf (Paleozoic to early Mesozoic). Compressional Laramide basin (Cretaceous to Recent)
Depositional Setting	Shallow-water carbonate and clastic shelf
Potential Reservoirs	Carbonate reef mounds and facies fronts; fractured carbonates; sandstone lenses
Regional Structure	Long wavelength open folds; minor expansion faults; thrusting in southern portion of basin
Seals	Marine shales and tight carbonates
Source Rocks	Shales and organic rich carbonates
Depth to Oil/Gas Windows .	1800-2900 m
Total Number of Wells	1 in US; none in Canada (3 wells in outcrop belt east of basin)
Seismic Coverage	Approximately 200 km along basin margins in Canada (all pre-1980)
Pipelines	None
Area	9209 km ² (83% in Alaska)
Area under Licence	None (in Canada)

The Kandik Basin is in the early stages of exploration. There is potential for small to moderate sized oil and gas pools in Lower Cretaceous to Upper Devonian and upper Proterozoic sandstones in combined structural-unconformity and thrust-related traps. Triassic, Permian, Carboniferous and Paleozoic carbonates have the potential for stratigraphic traps.

Geological Setting (Fig. 34)

The Kandik Basin is a Paleozoic-Mesozoic basin preserved within the Cordillera. It straddles the Yukon/Alaska border, 907 km southeast of Prudhoe Bay and 2600 km northwest of Calgary. The extent of Mesozoic sediments delimits the basin, which is surrounded by outcrop belts of unmetamorphosed Precambrian and Palaeozoic rocks. The basin underwent east-west compression in the Late Cretaceous and Tertiary, resulting in uplift and the development of thrust-folds.

Exploration History

Petroleum exploration in the Canadian portion of the basin began in 1970 with the drilling of the INC Husky Amoco Blackfly YT M-55 well near the eastern margin of the basin. The M-55 well was spudded on Blackfly Dome in Permian Jungle Creek sandstone. The well drilled to a total depth of 2070 m, ending in Devonian to Carboniferous Ford Lake shales. Inexco Husky et al. Porcupine YT G-31 (1972) penetrated 2658 m to upper Proterozoic Tinder Group sediments. The most recent well drilled in Canada (also in 1972) was Inexco et al.

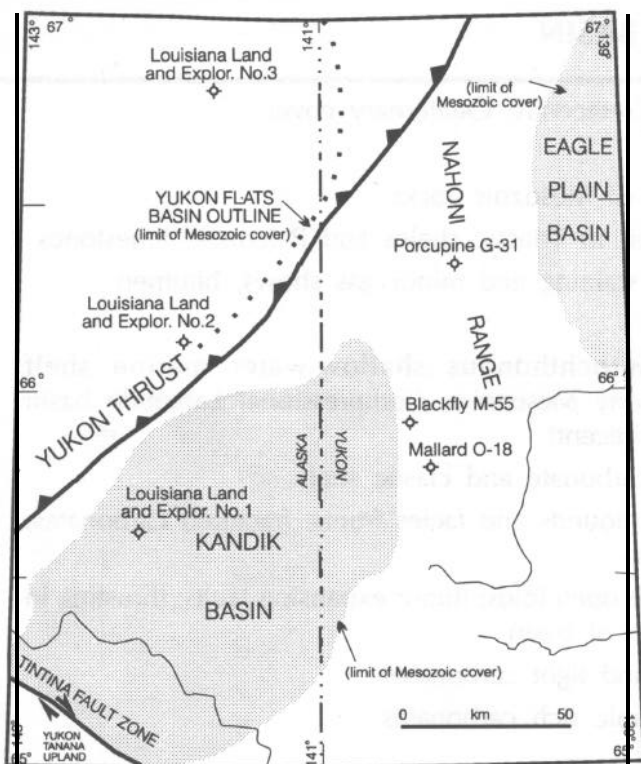


Figure 34. Basin outline and location of wells, Kandik Basin and adjacent areas.

Mallard Y.T. O-18, which was drilled on a thrust-faulted anticline with Carboniferous Hart River strata exposed at surface. The well penetrated 3200 m of fault-repeated Hart River strata. None of these wells encountered hydrocarbons.

In addition, one well has been drilled in the Alaska portion of the basin. In 1976, Louisiana Land and Exploration No. 1 drilled 3367 m to the Permian Jungle Creek Formation. It did not encounter commercial hydrocarbons, but dead oil and oil staining was noted in the cuttings and several gas "kicks" were encountered while drilling. In 1977, two additional wells (Louisiana Land and Exploration No. 2 and 3) were drilled in the shallower Yukon Flats Basin to the north of the Kandik Basin. Both failed to encounter hydrocarbons.

Stratigraphy (Figs. 35, 36)

The Kandik Basin contains over 11 km of Paleozoic to Recent strata confined by Precambrian to Permian outcrop around the basin margin.

The upper Proterozoic Tindir Group is composed of deep-water diamictites, clastics, dolomites and siliceous limestones. These strata are unconformably overlain by

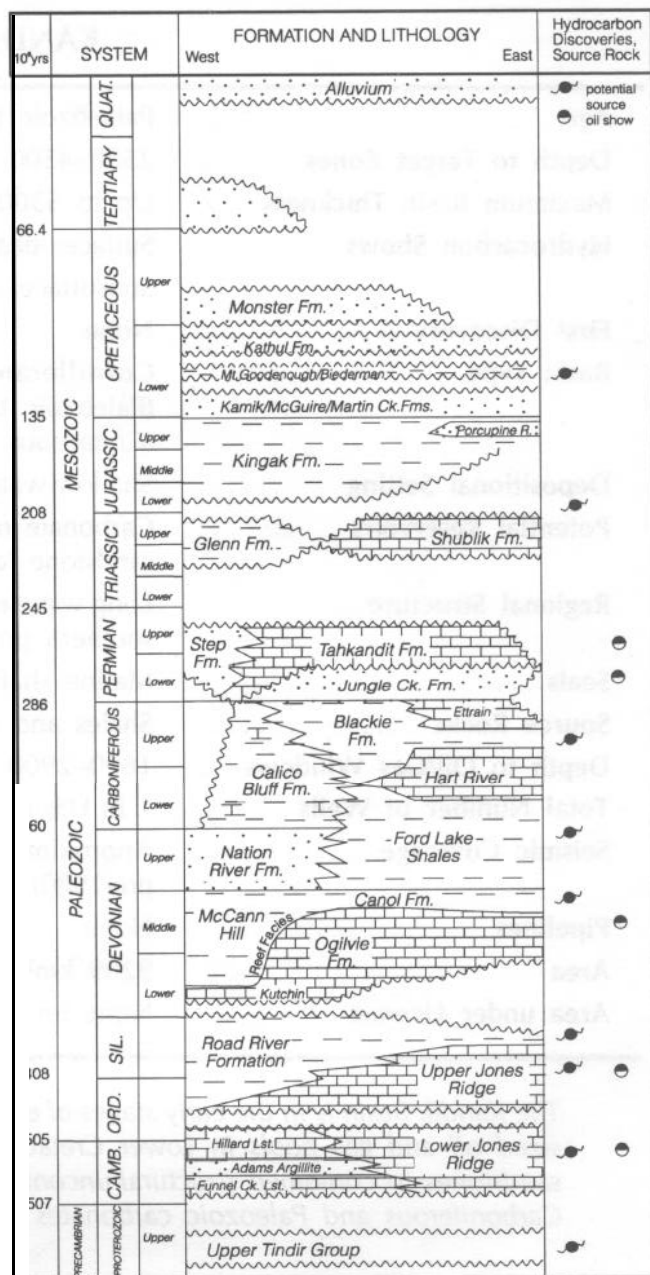


Figure 35. Stratigraphy of the Kandik Basin.

a series of carbonate/shale- cycles in the Paleozoic. The first cycle is represented by dolomitic limestones of the Jones Ridge Formation (Cambrian-Ordovician), which unconformably overlie the Tindir Group, and by the Road River shales (Ordovician-Silurian). The second cycle is represented by Devonian platform dolomites and limestones of the Ogilvie Formation and by cherty shales of the McCann Hill Formation (in Alaska) and the Canol shale (in Canada).

During the Late Devonian, sedimentation on the Paleozoic shelf became dominated by clastics with

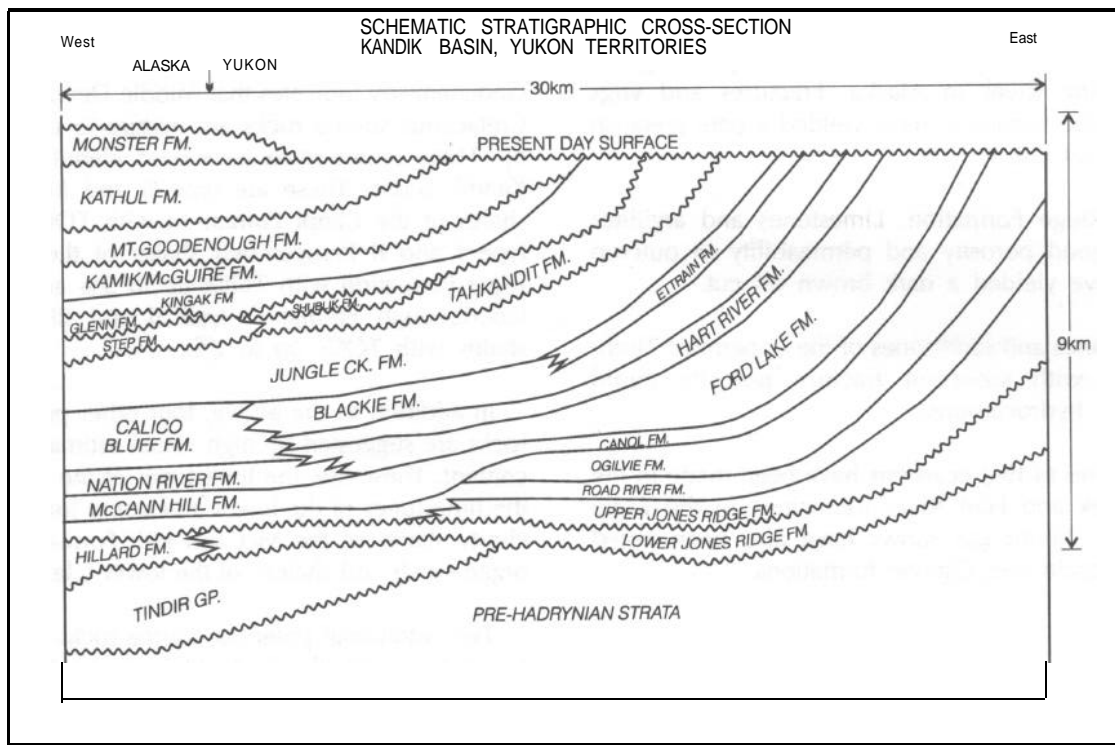


Figure 36. Schematic stratigraphic cross-section, Kandik Basin.

deposition of the Nation River Formation in the west and thick Ford Lake shales in the east. Carbonate sedimentation resumed during the Mississippian in the eastern basin with the deposition of the Hart River Formation, contemporaneously with bituminous calcareous shales and shaly limestones of the Calico Bluff Formation. Another cycle is represented by shaly clastics of the Lower to Upper Carboniferous Blackie Formation and cherty limestones and dolomites of the Upper Carboniferous Ettrain Formation, which conformably overlie Hart River and Calico Bluff strata.

The Ettrain/Blackie package is overlain by calcareous sandstones of the Permian Jungle Creek Formation, and by Upper Permian argillaceous, cherty limestones of the Tahkandit Formation. The Tahkandit strata grade westward into coarse limey clastics of the Step Formation.

A major unconformity separates the Tahkandit/Step strata from the overlying upper Triassic Shublik limestone and its western equivalent - the organic-rich "oil" shales of the Glenn Formation. Thick shales of the Jurassic Kingak Formation unconformably overlie Triassic strata. These, in turn, are overlain by Cretaceous strata composed of recurrent clastic wedges separated by unconformities. The Cretaceous strata

include sandstones and shaly siltstones of the Martin Creek, Kamik, Mount Goodenough and Kathul formations, and conglomeratic sandstones of the Monster Formation. Unconformably overlying the Cretaceous are Quaternary to Recent alluvial sediments.

Potential Reservoirs

Potential for reservoir development exists in the following horizons:

- 1) Tahkandit Formation limestones. In the Alaska portion of the basin, these strata show local porous zones containing a dark brown oil stain.
- 2) Jungle Creek (Calico Bluff) calcareous sandstones. In the Alaska portion of the basin these strata have yielded a pale reddish brown oil cut.
- 3) Ettrain Formation. Within the Kandik Basin the Ettrain limestones are almost twice as thick as those in the Eagle Plain Basin.
- 4) Hart River Formation limestones and calcareous sandstones.

- 5) Ogilvie Formation. Reefal carbonates have good porosity and permeability in outcrop along the Porcupine River in Alaska. Fractures and vugs within the formation have yielded a pale greenish brown oil cut.
- 6) Jones Ridge Formation. Limestones and argillites show good porosity and permeability in outcrop and have yielded a dark brown oil cut.
- 7) Limestones and sandstones of the uppermost Tindir Group with sufficient fracture porosity could contain hydrocarbons.

Discoveries of hydrocarbons have been made in the Jungle Creek and Hart River formations in the Eagle Plain Basin. Minor gas shows have also been noted from the Ettrain and Ogilvie formations.

Structure, Traps and Seal

The Kandik Basin was pervasively folded and faulted during the Late Cretaceous to Tertiary. Fold axes trend northeastward and relate to wrench movement along the Tintina Fault zone at the southern margin of the basin. Proterozoic and Paleozoic rocks form broad open folds with little fracturing along the hinge lines while Mesozoic and Cenozoic rocks form tight isoclinal folds with fractured hinge lines and steep, commonly overturned limbs.

At least two orthogonal sets of Cretaceous or younger high-angle faults are present within the basin. Low-angle thrust faults have been mapped in the Canadian portion of the basin making over-thrust traps a possibility in this area.

Shales of the Mount Goodenough, McGuire, Kingak, and Ford Lake formations are potential seals for Carboniferous and Cretaceous units. Facies transitions from carbonate to shale (Ogilvie/McCann and Ettrain/Blackie) and from sandstone to shale (Nation River/Ford Lake) are potential lateral seals for lower Paleozoic units. The Canol and upper Road River shales, although relatively thin, could act as top seals for Middle Devonian and older reservoirs. The Lower Cretaceous Kingak Formation could form a regional top seal for reservoirs truncated by the sub-Jurassic unconformity.

Source Rocks

Geochemistry indicates that Middle Devonian to Lower Cretaceous source rocks are mature to overmature for oil. Three source rocks have been identified within the Kandik Basin. These are type II and III kerogen-rich shales of the Canol Formation with TOCs up to 7%; type I and II kerogen-rich shales of the upper Road River Formation with TOCs up to 5% and the Mount Goodenough Formation type II and III kerogen-rich shales with TOCs up to 2%.

In addition to the above, four other possible source rocks are suggested by high visual estimates of organic content. These are: the limestones of the Tindir Group; the limestones of the lower and upper Jones Ridge; the cherty shales of the McCann Hill Formation, and the organic-rich "oil shales" of the lower Glenn Formation.

Two additional potential source rocks are suggested by analogy with the Eagle Plain Basin. Both the Ford Lake and Blackie formations contain type II and III kerogen but may be overmature for oil in the Kandik Basin.

Potential

The geology of the Kandik Basin is comparable with the neighbouring Eagle Plain Basin in which several oil and gas discoveries have been made. Similar stratigraphy and trap styles suggest moderate to high potential for discoveries in upper Paleozoic to Mesozoic rocks, particularly in stratigraphic and sub-unconformity traps along the crest of folds and associated with faults. In the Canadian portion of the Kandik Basin, over-thrust traps are an additional possibility. Additional plays, but more risky, are structural/stratigraphic traps associated with facies changes. Lower Paleozoic potential may exist in the carbonate to shale transition zones in the Cambrian through Devonian carbonate sequences.

The high exploration risk for plays in the basin relates to reservoir facies development, porosity preservation, source rock maturity, and timing of migration to coincide with Cretaceous tectonics.

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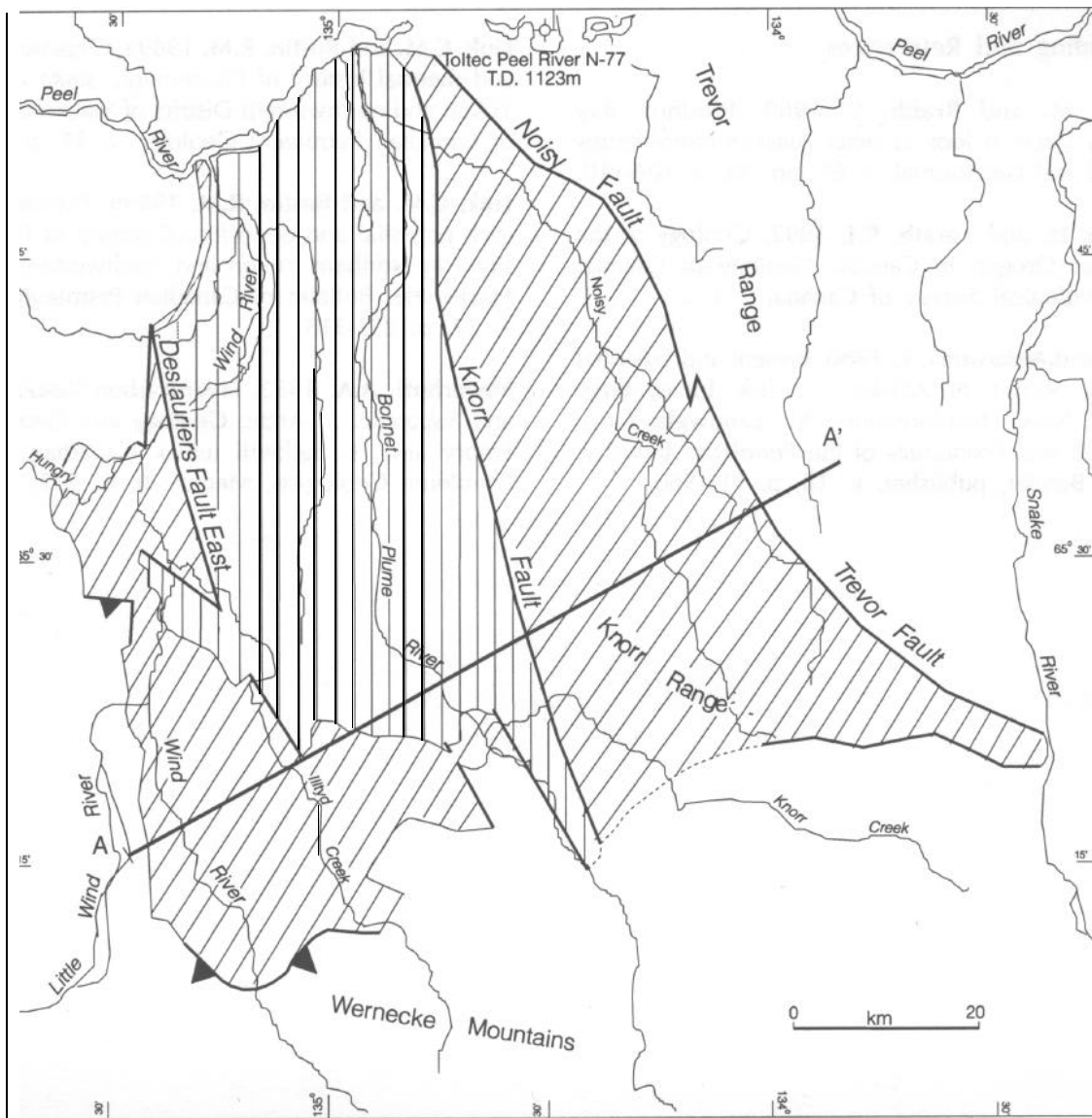


Figure 37. The ancestral (diagonal plus vertical patterns) and preserved (vertical pattern) Bonnet Plume Basin (after Norris and Hopkins, 1977).

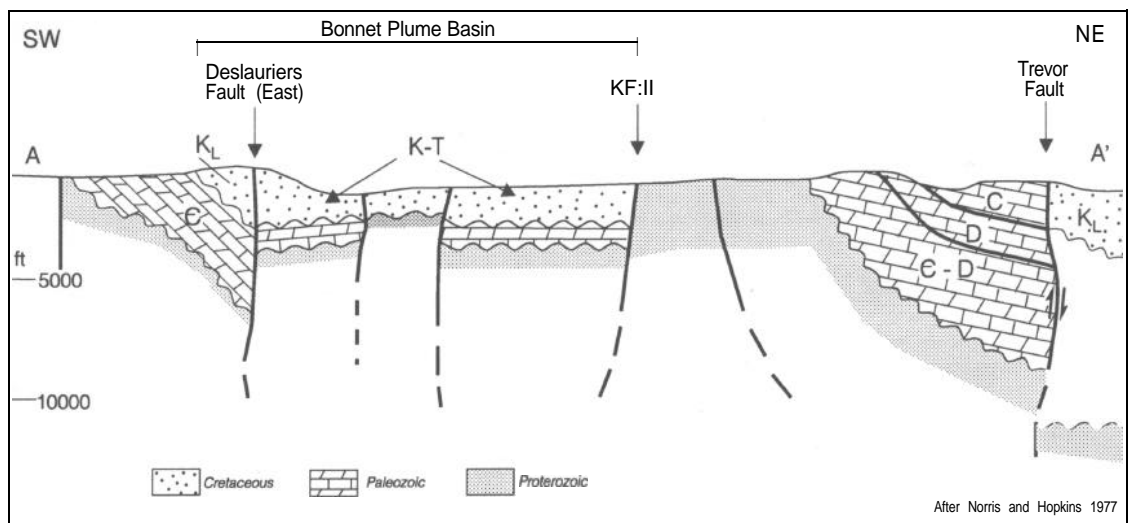


Figure 38. Schematic cross-section, Bonnet Plume Basin (after Norris and Hopkins, 1977).

BONNET PLUME BASIN

(Figs. 37, 38)

Age	Late Early Cretaceous to Early Tertiary
Maximum Basin Thickness	Up to 700 m(?)
First Discovery	None
Basin Type	Intermontane
Depositional Setting	Alluvial, continental
Potential Reservoirs	Cretaceous sandstones and conglomerates
Regional Structure	Block faulting: overthrust at south
Seals	Intraformational shales, overthrust sheets
Source Rocks	Subcropping Upper Devonian to Mississippian shales
Depth to Oil Window	Not known
Total Number of Wells	None (nearest well is Toltec Peel River YT N-77, drilled in 1970, 20 km to northwest of basin)
Seismic Coverage	None
Area	40,000 km ²
Area under Licence	None

Thin Quaternary deposits mask the Albian to ?Paleocene Bonnet Plume Formation, comprising conglomerates and sandstones succeeded by sandstones, shales and lignites. Across most of the basin, the Cretaceous overlies block faulted and deeply truncated Proterozoic rocks. To the southwest, Cretaceous rocks thicken and may overlie possible source rocks of the Paleozoic Road River, Canol and ?Ford Lake formations. The southern margin of the basin is overthrust by Proterozoic and Cambrian rocks creating a high-risk subthrust play in the Wernecke Mountains. With shallow targets, poor seals and only local preservation of possible source rock, overall oil and gas potential must be rated as low.

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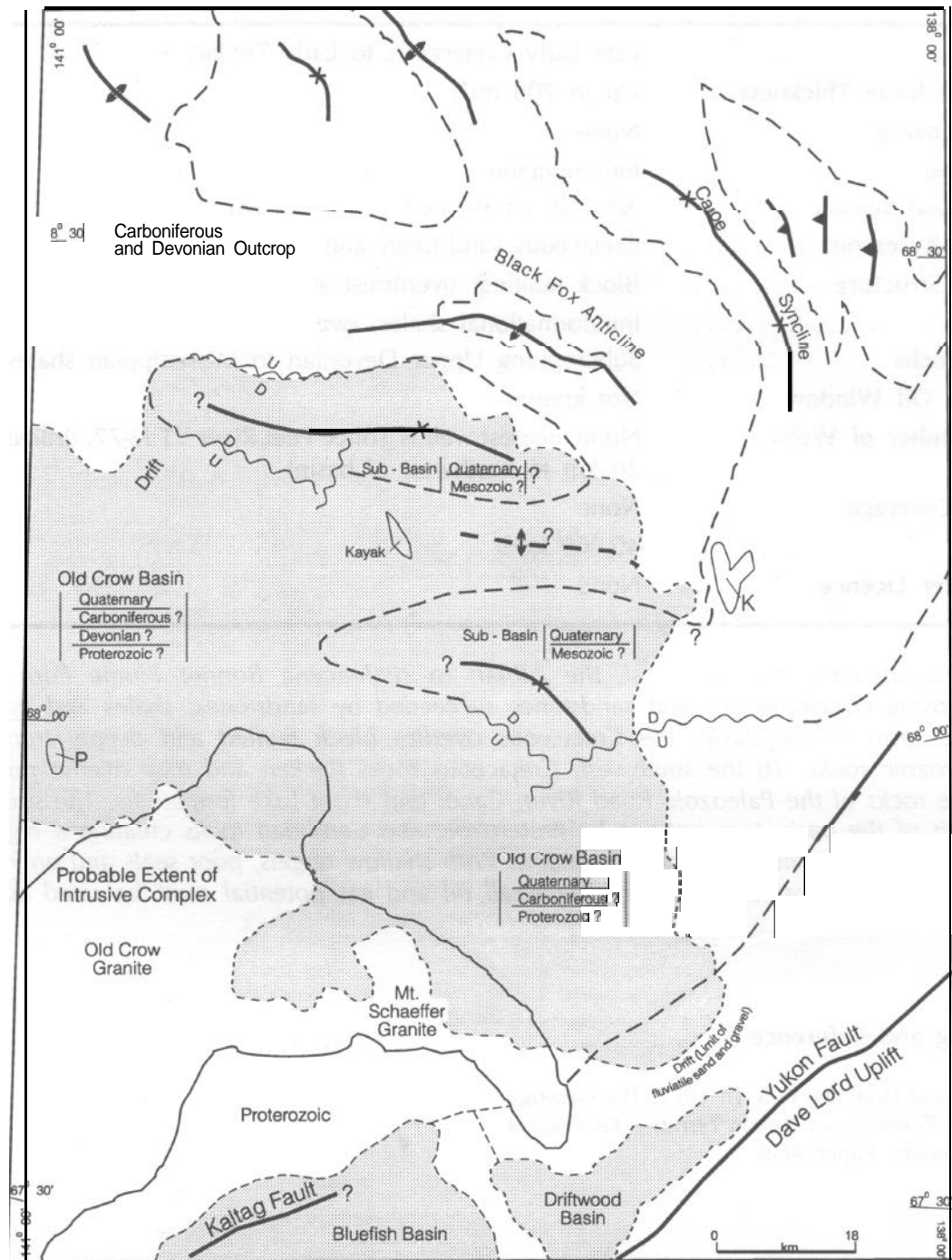


Figure 39. Geological features of Old Crow Basin and adjacent areas.

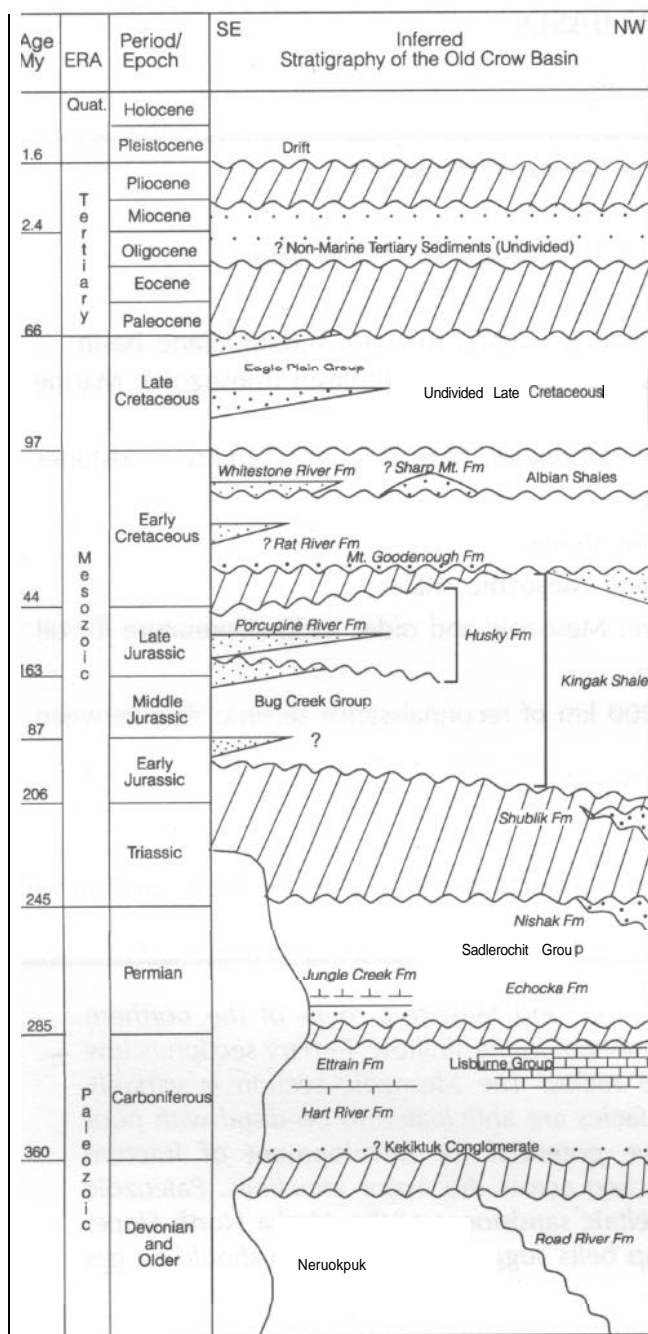
OLD CROW BASIN

(Figs. 39, 40)

Age	Tertiary overlying Paleozoic/?Mesozoic
Depth to Target Zones	1-3 k m
Maximum Basin Thickness	2 km (Tertiary); 4 km ?Mesozoic + Paleozoic
First Discovery	None
Basin Type	Tectonically deformed cratonic margin; intermontane basin
Depositional Setting	Alluvial (Tertiary). Distal marine shelf/basin (Mesozoic). Marine carbonate shelf/basin (Paleozoic)
Potential Reservoirs	Upper Paleozoic carbonates, Mesozoic and Tertiary sandstones
Regional Structure	Faulted anticlines
Seals	?Mesozoic marine shales
Source Rocks	?Carboniferous and Mesozoic shales
Depth to Oil Window	Tertiary immature; Mesozoic and older rocks overmature for oil
Total Number of Wells	None
Seismic Coverage	Approximately 200 km of reconnaissance seismic shot between 1969 and 1972
Area	75,000 km ²
Area under Licence	None

(Flat terrain of muskeg and lakes. Lightly forested. The sole population centre is at Old Crow (airstrip) with no road access from the Dempster highway.)

A shallow Tertiary basin overlying folded Paleozoic and Mesozoic rocks of the northern Cordilleran foldbelt. The basin is undrilled and potential in the shallow Tertiary section is low (lack of structure, poor seals, immature source rocks). The Mesozoic section is variably preserved in the axes of synclines: sedimentary facies are anticipated to be distal with poor reservoir potential. Paleozoic carbonates have potential for development of fracture enhanced diagenetic porosity, but may be breached across the major anticlines. Paleozoic clastics – if present – are distal equivalents of deltaic sandstones of the Alaska North Slope. Source rock maturation from surrounding outcrop belts suggest that the basin should be gas prone.



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Figure 40. Inferred stratigraphy of Old Crow Basin.

CHAPTER 4 — MACKENZIE DELTA AND BEAUFORT SEA

SOUTHERN MACKENZIE DELTA AND TUKTOYAKTUK PENINSULA

Age	Jurassic to Early Cretaceous overlying Paleozoic and underlying the landward margin of the Tertiary Beaufort-Mackenzie Basin
Depth to Target Zones	1000-5000 m
First Discovery	1969 (I.O.E. Atkinson H-25 oil discovery). There have been 7 subsequent discoveries in Lower Cretaceous or older reservoirs, the largest being the Parsons Lake gas field
Discovered Resources	Gas: 60.2 x E9 m ³ (2.13 tcf) in 2 discoveries Oil: 11.2 x E6 m ³ (70.5 mmbbls) in 6 discoveries Condensate: 7.0 x E6 m ³ (44.0 mmbbls)
Production	None
Basin Type	Rifted continental margin
Depositional Setting	Shoreface, deltaic, marine shelf
Reservoirs	Wave-dominated deltaic sandstones, shelf sandstones
Regional Structure	Extensional faulting with superimposed compression restricted to the west
Seals	Marine shales
Source Rocks	Upper Jurassic shales (gas-prone); Upper Cretaceous basalinal shales (oil-prone)
Depth to Oil Window	3000 m
Total Number of Wells	68 exploratory (penetrating to Lower Cretaceous strata); 13 delineation; 81 (out of 239 wells in the Beaufort-Mackenzie region)
Seismic Coverage	Tuktoyaktuk Peninsula: extensive grid Southern Mackenzie Delta: older vintage (dynamite) and sparser coverage
Pipelines	None

(Accessible and easy terrain for winter operations, but extreme winter temperatures. Boreal forest in southern delta, tundra in north. Dempster Highway all-season road to Inuvik. Winter road on to Tuktoyaktuk. Administrative centre at Inuvik. Experienced local labour force and contractors.)

One major onshore gas discovery, and one gas/condensate discovery, both with development potential, have been made on the Tuktoyaktuk Peninsula. This rifted Mesozoic margin juxtaposes excellent Lower Cretaceous reservoirs and mature oil-prone Upper Cretaceous source rocks. A number of small oil discoveries have been made but the potential for larger pools is high. Jurassic sandstones and Paleozoic sandstones and carbonates are also potential reservoir rocks: all are up-dip from the hydrocarbon kitchen within the thick sedimentary pile immediately to the north. Exploration is onshore and close to proposed pipeline routes.

Geological Setting (Figs. 41-44)

Mesozoic and older strata rise to within drilling depth beneath the southern Mackenzie Delta, on the flank of the Tuktoyaktuk Peninsula and beneath the Yukon Coastal Plain. They are overlain by Upper Cretaceous strata and a southward-thinning wedge of Tertiary/Quaternary deposits. The strata outcrop in the northern Richardson Mountains and in the mountains backing the Yukon Coastal Plain.

Along the Tuktoyaktuk Peninsula, the Mesozoic is preserved in downfaulted blocks along the Eskimo Lakes Arch and in the adjacent Kugmallit Trough. Paleozoic and Proterozoic rocks subcrop beneath a Quaternary cover along the axis of the Eskimo Lakes Arch, outcropping as an inlier of Proterozoic and Cambrian to Devonian strata at Campbell Lake, just south of Inuvik. The Mesozoic rifted margin superseded an early Paleozoic continental margin, which was deeply eroded prior to Mesozoic deposition.

Long, continuous, sub-parallel extension faults of the Eskimo Lakes Fault system on the Tuktoyaktuk Peninsula trend northeast, delimiting the inner limit of rifting along the continental margin. In the southern Mackenzie Delta, this fault system intersects the Cordilleran thrust front in the northern Richardson Mountains. Lower Cretaceous and upper Paleozoic strata in this area, originally deposited in an extensional tectonic regime, have been uplifted, folded and possibly thrust faulted.

Exploration History (Fig. 45)

Onshore drilling on the Tuktoyaktuk Peninsula began in 1969 and met with initial success at Atkinson Point. This small oil discovery in Cretaceous sandstones was followed by a major gas find in 1970 at Parsons Lake in the Kamik Formation, and, in the same year, by a second oil discovery at Mayogiak in Paleozoic carbonates. Subsequent drilling was rewarded by two

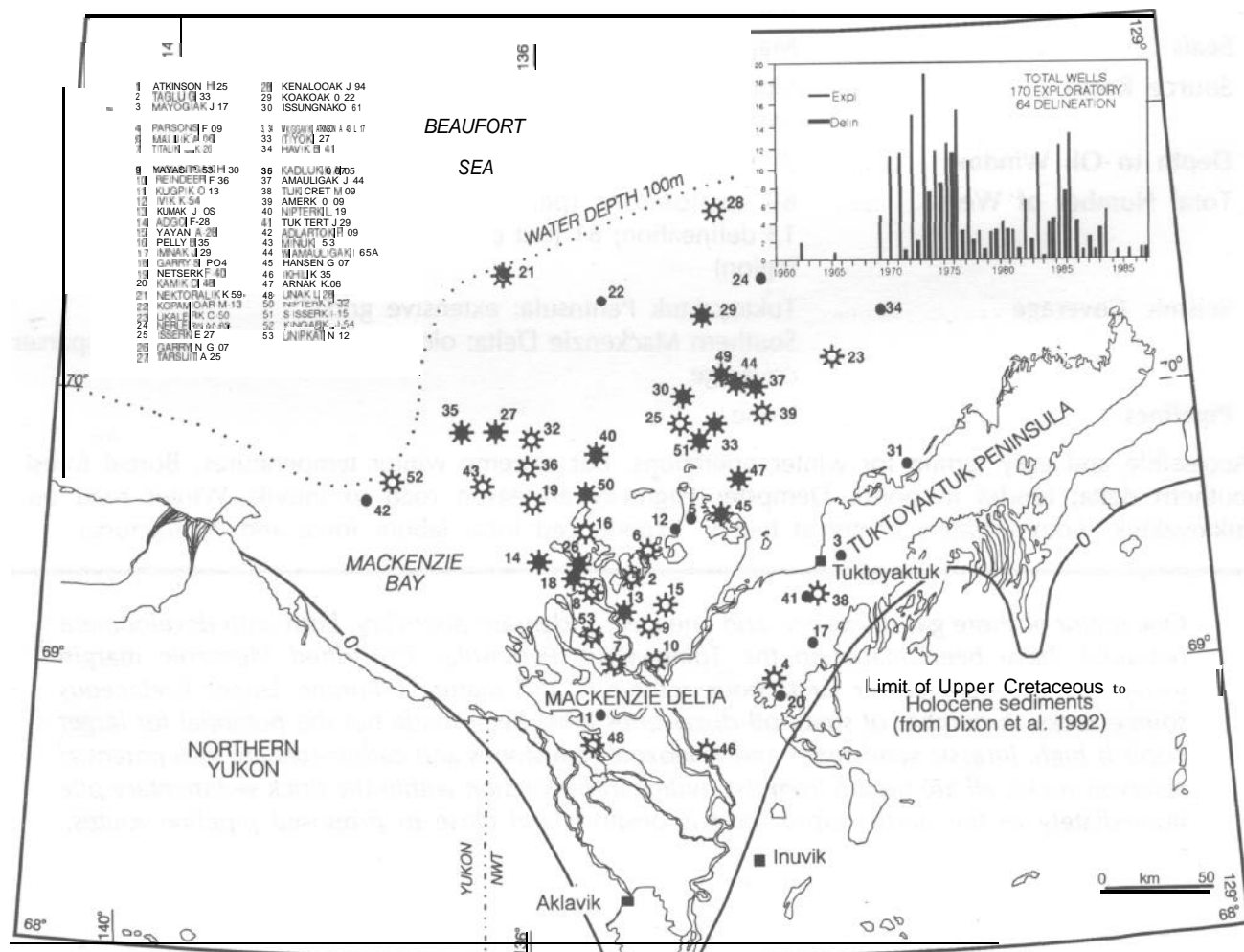


Figure 41. Oil and gas discoveries in the Beaufort-Mackenzie area.

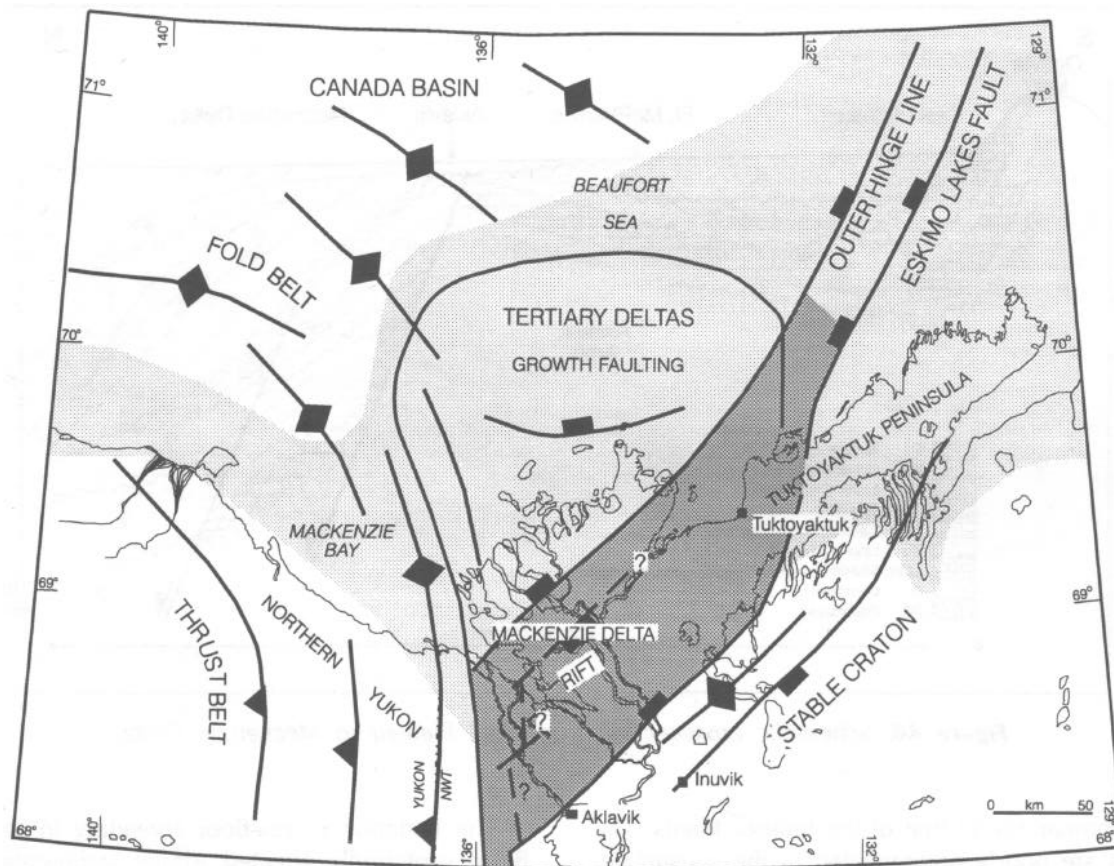


Figure 42. Structural elements of the Beaufort-Mackenzie area.

small discoveries of oil at Imnak and Kamik close to Parsons Lake, followed by a significant gas/condensate discovery at Tuk L-09. The oil discovery at West Atkinson is the only offshore discovery in a Lower Cretaceous reservoir. After 1977, the focus of exploration shifted offshore to the Tertiary basin.

In the southern Mackenzie Delta, oil was discovered at Kugpik in 1973 (also in the Kamik Formation) but subsequent exploration has been sparse. The sole reward has been a show of gas at Shell Unak L-28.

Drilling on the Yukon Coastal Plain has been limited to three wells with no shows and unpromising reservoir and source rock potential.

Stratigraphy

The Phanerozoic of the Tuktoyaktuk Peninsula is underlain by a thick succession of Proterozoic strata, which thins rapidly towards the Beaufort Sea. Quartzite is the commonest lithology encountered by the few wells penetrating the Proterozoic.

Eighteen wells have drilled into lower Paleozoic strata along the Tuktoyaktuk Peninsula. The lower Paleozoic succession comprises a thick carbonate

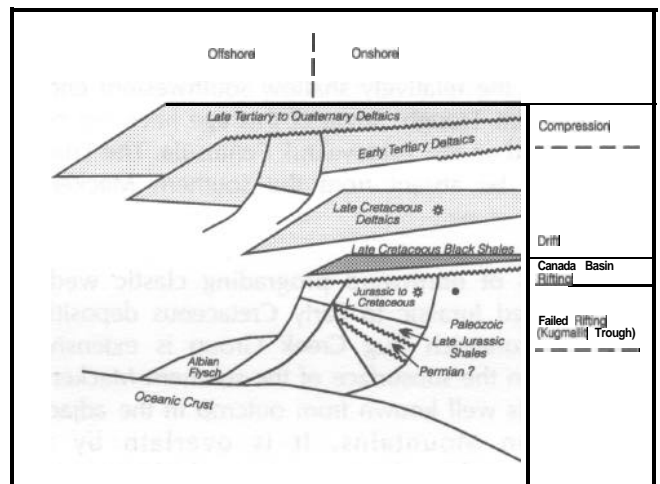


Figure 43. Tectono-stratigraphic relations between the Beaufort-Mackenzie Basin and the geology under Tuktoyaktuk Peninsula and southern Mackenzie Delta.

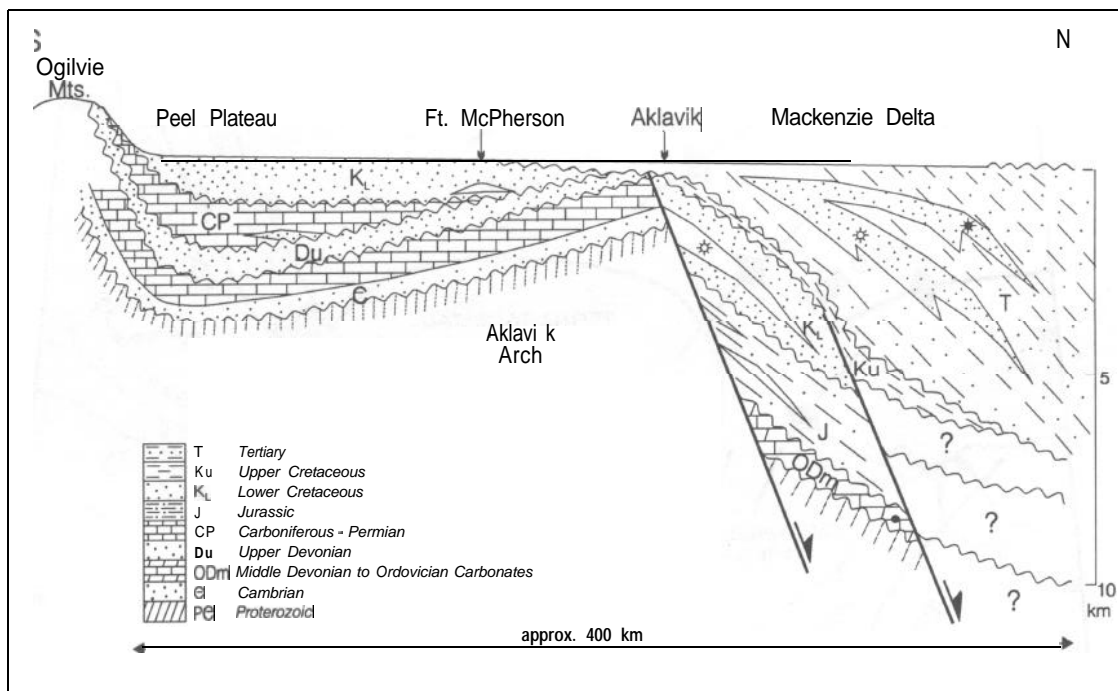


Figure 44. Schematic cross-section from Peel Plateau to Meckenzie Delta.

platform comparable to that of the Interior Plains. The carbonates are poorly differentiated in the subsurface: they correspond to the Franklin Mountain, Mount Kindle, Peel, Tatsieta, Arnica, Landry and Hume formations described from outcrop. In the west, the carbonates give way to shales of the Road River Formation, exposed in the Richardson and Barn mountains and penetrated by wells on the eastern flank of the Richardson Mountains.

Carboniferous and Permian rocks, corresponding to the Lisburne and Sadlerochit groups, are extensively preserved in the northern Yukon and have been drilled in wells in the relatively shallow southwestern end of the Kugmallit Trough. Strata of this age have not been encountered on the Tuktoyaktuk Peninsula. The Triassic appears to be absent from the southern Mackenzie Delta area.

A series of northward prograding clastic wedges characterized Jurassic to Early Cretaceous deposition. The sandstone-rich Bug Creek Group is extensively preserved in the subsurface of the southern Mackenzie Delta and is well known from outcrop in the adjacent Richardson Mountains. It is overlain by the shale-dominated Husky Formation, which is in turn succeeded by the Parsons Group (including the thick Kamik sandstone). Post-Hauterivian strata include the Rat River Formation sandstones in the southern Mackenzie Delta and their approximate equivalent, the Atkinson Point Formation, on the Tuktoyaktuk Peninsula.

The initiation of sea-floor spreading in the Canada Basin profoundly affected Albian sedimentation. The thick flysch deposits of this period were deposited in a rapidly subsiding basin. These deposits are the precursors of the thick depositional sequences of the Late Cretaceous and Tertiary successor basin.

Potential Reservoirs

Discoveries have been made in Paleozoic carbonates, Hauterivian sandstones of the Parsons Group and Barremian sandstones of the Rat River and Atkinson Point formations. Significant shows have been noted in Mississippian carbonates at Shell Unak L-28 and in the Permian at Shell Kugpik L-24.

The Kamik sandstones of the Parsons Group are the thickest, most extensively developed reservoir unit in the area. Net pay at Parsons Lake varies from 40 to 60 m with average porosity of 15%. Distal facies of the Kamik may exist within the Kugmallit Trough, but the characteristics of these sandstones are unknown.

Sandstones of the Jurassic Bug Creek Group have fair potential as reservoir sandstones. These units were deposited as shelf sandstones prior to significant rifting and subsidence in the region. They are thinner than the Kamik sandstones with porosity exceeding 10% in the cleaner facies but with low permeability. Paleozoic rocks also have some potential as reservoirs in the south delta area. Reservoir characteristics may be locally enhanced in the south delta by fractures.

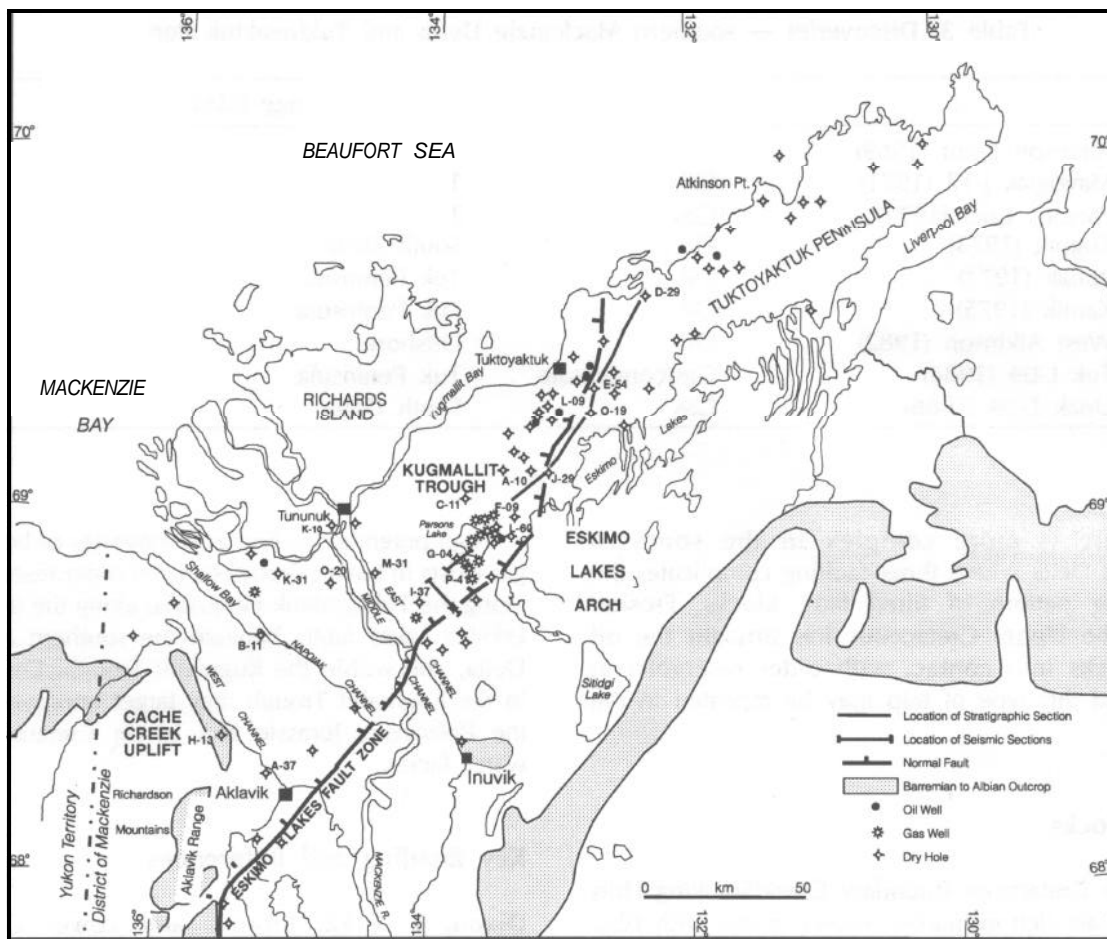


Figure 45. Wells penetrating Mesozoic strata on Tuktoyaktuk Peninsula and south Mackenzie Delta.

Secondary porosity development in lower Paleozoic carbonates has been encountered along the trend of the Eskimo Lakes Fault system at Mayogiak and West Atkinson. Such porosity development may pervade certain fault lines and volumetrically significant accumulations in such traps are a possibility.

Structure, Traps and Seal

The Eskimo Lakes Fault system comprises a set of sub-parallel, normal faults. The principal faults have major downthrow to the northwest into the Kugmallit Trough, but faults with lesser throws are numerous and some of these downthrow to the southeast. Cross-fault seal may be poor between the faults of smaller throw: a field-wide gas-water contact is present at Parsons Lake field, despite the numerous fault compartments present. In addition to the predominant northeast-southwest trend of the main faults, a conjugate fault system is present, but throws on this system are minor.

The Kugmallit Trough has the potential to contain thick sequences of Lower Cretaceous sandstones deposited in a rapidly subsiding trough. Rotation and distal pinchout of sandstones may have created deep stratigraphic traps. An intra-graben high, the Napoiak High, and the remnants of the northwestern rim of the Kugmallit Trough (the Tununuk High) are poorly defined by the existing seismic grid.

Marine shales within the Lower Cretaceous are effective top seals and, along the bevelled margin of the rifted blocks, reservoirs may be in direct contact with the seal/source rocks of the Upper Cretaceous Boundary Creek and Smoking Hills formations. The Jurassic shales of the Husky Formation also are potential seals for possible pre-Mesozoic reservoirs within the Kugmallit Trough.

Traps are principally structural but pinch-out and channelling in the sandstone reservoirs lend a stratigraphic element to trapping that has not been fully explored.

Table 3. Discoveries — Southern Mackenzie Delta and Tuktoyaktuk Peninsula

Range (MMB/BCF)			
Atkinson Point (1969)	Oil	Tuk Peninsula	25-100
Mayogiak J-1 7 (1971)	Oil	Tuk Peninsula	< 10
Parsons Lake (1971)	Gas	Tuk Peninsula	1000-2000
Kugpik (1973)	Oil	South Delta	10-25
Imnak (1974)	Oil	Tuk Peninsula	10-25
Kamik (1975)	Oil	Tuk Peninsula	<10
West Atkinson (1982)	Oil	Offshore	10-25
Tuk L-09 (1984)	Gas/condensate	Tuk Peninsula	100-500
Unak L-28 (1986)	Gas	South Delta	?

Structure is more complex in the southern Mackenzie Delta where thrust-faulting complicates the pre-existing pattern of tilted fault blocks. Erosion beneath the Upper Cretaceous has brought the oil source rocks into contact with older reservoirs at Kugpik and this type of trap may be repeated in the area.

Source Rocks

The Upper Cretaceous Boundary Creek/Smoking Hills sequences are rich in marine organic matter with TOC ranging from 2 to 10%. These are rich potential sources of oil. Oil-source studies show this unit as the source of oil in Mayogiak and Atkinson Point. The Upper Jurassic Husky shales are considered potential source rocks and a possible source of gas and condensate at Parsons Lake. Other potential source rocks may also exist within the Lower Cretaceous succession.

Potential

The potential of this area was assessed by the Geological Survey of Canada in 1988 (Dixon et al., 1994). Five plays were assessed using a probabilistic methodology, but the potential of the Lower Cretaceous and older strata was not distinguished from onshore Tertiary plays.

High potential for further discoveries of both oil and gas exists in Lower Cretaceous and older reservoir rocks along the Tuktoyaktuk Peninsula, along the trend of the Eskimo Lakes faults beneath the southern Mackenzie Delta, and within the Kugmallit Trough. Deep drilling in the Kugmallit Trough may target unproven plays in the Paleozoic, Jurassic and Lower Cretaceous water

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BEAUFORT-MACKENZIE BASIN

Age	Late Cretaceous to Recent
Depth to Target Zones	Offshore: 2000-6000 m Onshore: 600-3000 m
Maximum Basin Thickness	12-16 km
First Discovery	1971 (I.O.E. Taglu G-33 gas discovery). There have been 45 discoveries in Tertiary reservoirs
Discovered Resources	Gas: 300 x E9m ³ (10.7 tcf) Oil: 212 x E6m ³ (1310 mmbbls) Condensate: 10.5 x E6m ³ (66 mmbbls)
Production	Extended test production of oil from Amauligak Field
Basin Type	Delta
Depositional Setting	Delta-plain, delta-front, prodelta, parallic
Reservoirs	Thick contiguous deltaic sandstones, shelf and deep-water sandstones
Regional Structure	Extensional faulting with superimposed compression
Seals	Transgressional tongues of marine shale, overpressured at depth
Source Rocks	Upper Cretaceous basinal shales and Lower Tertiary delta-front shales
Depth to Oil Window	5000 m
Total Number of Wells	178 exploratory (62 offshore), 61 delineation (21 offshore); total 239 (83 offshore)
Pipelines	None
Area	66,000 km ² approximately 70% in water depths up to 100 m at shelf edge and 30% on the Mackenzie Delta
Area under Licence	Exploration Licences: 133,659 ha Significant Discovery Licences: 111,543 ha

(Population centres at Tuktoyaktuk and Inuvik with experienced local labour force and contractors. Administrative centre at Inuvik. Offshore operations constrained by ice and short open-water season, but operating periods have been extended with new offshore platforms and innovative operating techniques. Onshore and shallow-water operations restricted to winter season.)

Analogous to prolific delta basins around the world, the Beaufort-Mackenzie region is credited with 53 oil and/or gas discoveries both onshore and offshore. Forty-four of these discoveries are in the Tertiary basin. A large geophysical and well database is publicly available. The potential of the basin for further discoveries is high. New discoveries will strengthen the existing resource base in anticipation of development in the next decade.

Geological Setting (Figs. 46, 47)

The Beaufort-Mackenzie Basin occupies the southern end of the subsiding trough formed by the opening of the oceanic Canada Basin. The basin is confined by the Yukon Coastal Plain backed by the mountains of the

northern Cordillera to the southwest, and by the Tuktoyaktuk Peninsula, flanking the margin of the Canadian craton, to the southeast. From the Late Cretaceous and through the Tertiary period, sediments prograded northwards across the continental margin into the Canada Basin.

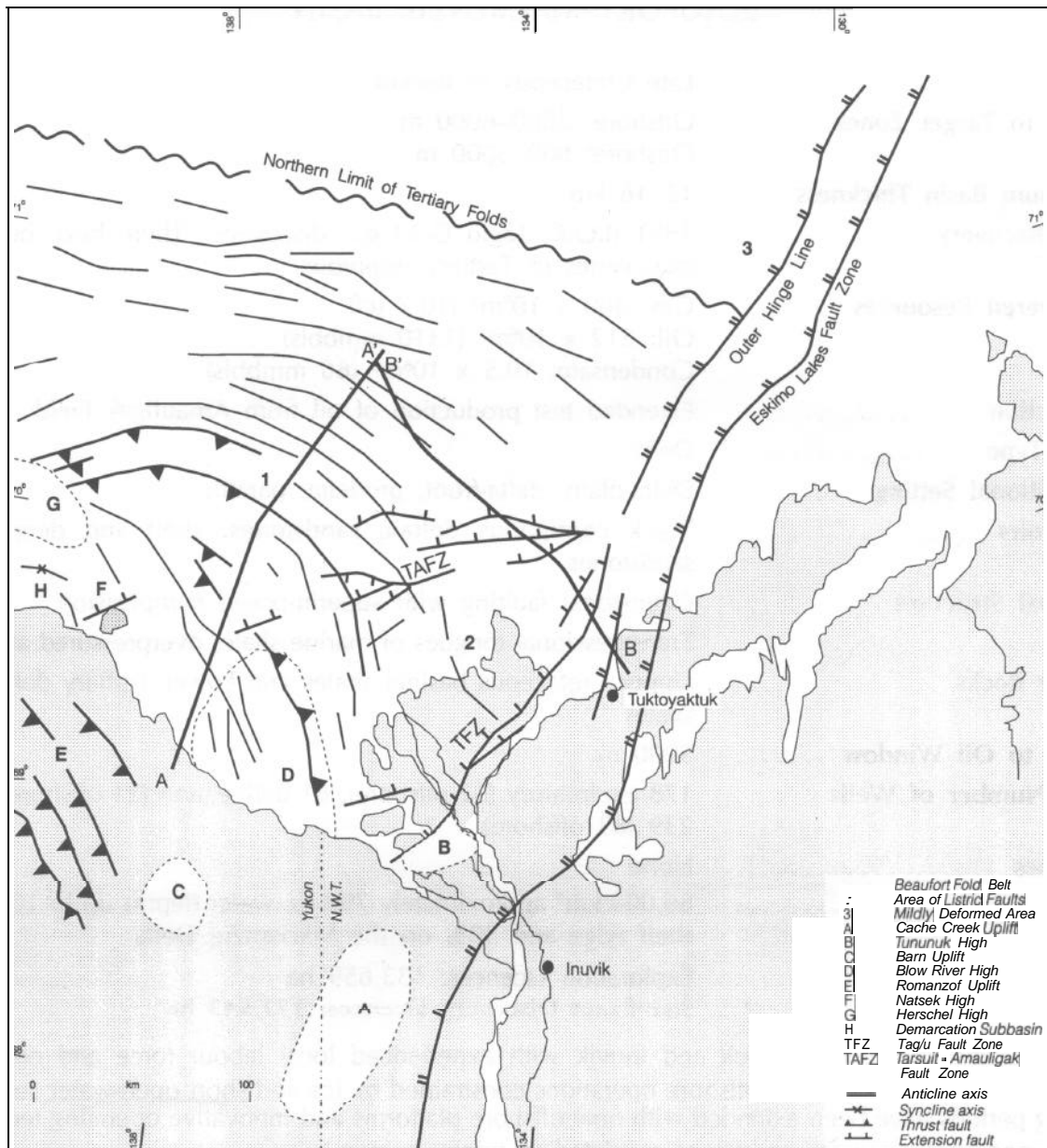


Figure 46. Structural trends in the Beaufort-Mackenzie Basin and location of cross-sections illustrated in Figure 47 (after Dixon et al., 1992).

The basin depocentre lies just north of Richards Island on the Mackenzie Delta where the basin-fill is predominantly deltaic. Laterally the basin merges into paralic shelf sediments with local deltaic influences that are contiguous with strata of the Kaktovik Basin of the Alaska Beaufort Sea to the northwest and the Banks Island Basin to the northeast. Subbasins occur along the continental margin, notably the Demarcation Basin and Herschel High, which extend into U.S. waters west of 141 °W.

The Beaufort-Mackenzie Basin is floored distally by oceanic crust, and proximally by progressively older

Mesozoic and Paleozoic strata, which outcrop in the mountains to the south and southwest, and on the Tuktoyaktuk Peninsula.

Exploration History (Fig. 48)

Onshore drilling in the basin and on the adjacent Tuktoyaktuk Peninsula began in 1969. Imperial Oil had early success at Taglu with the discovery of a major gas pool. Onshore drilling continued at a fast rate through the mid-decade of the 1970s. In the 1980s, exploration moved offshore, drawn by the numerous large

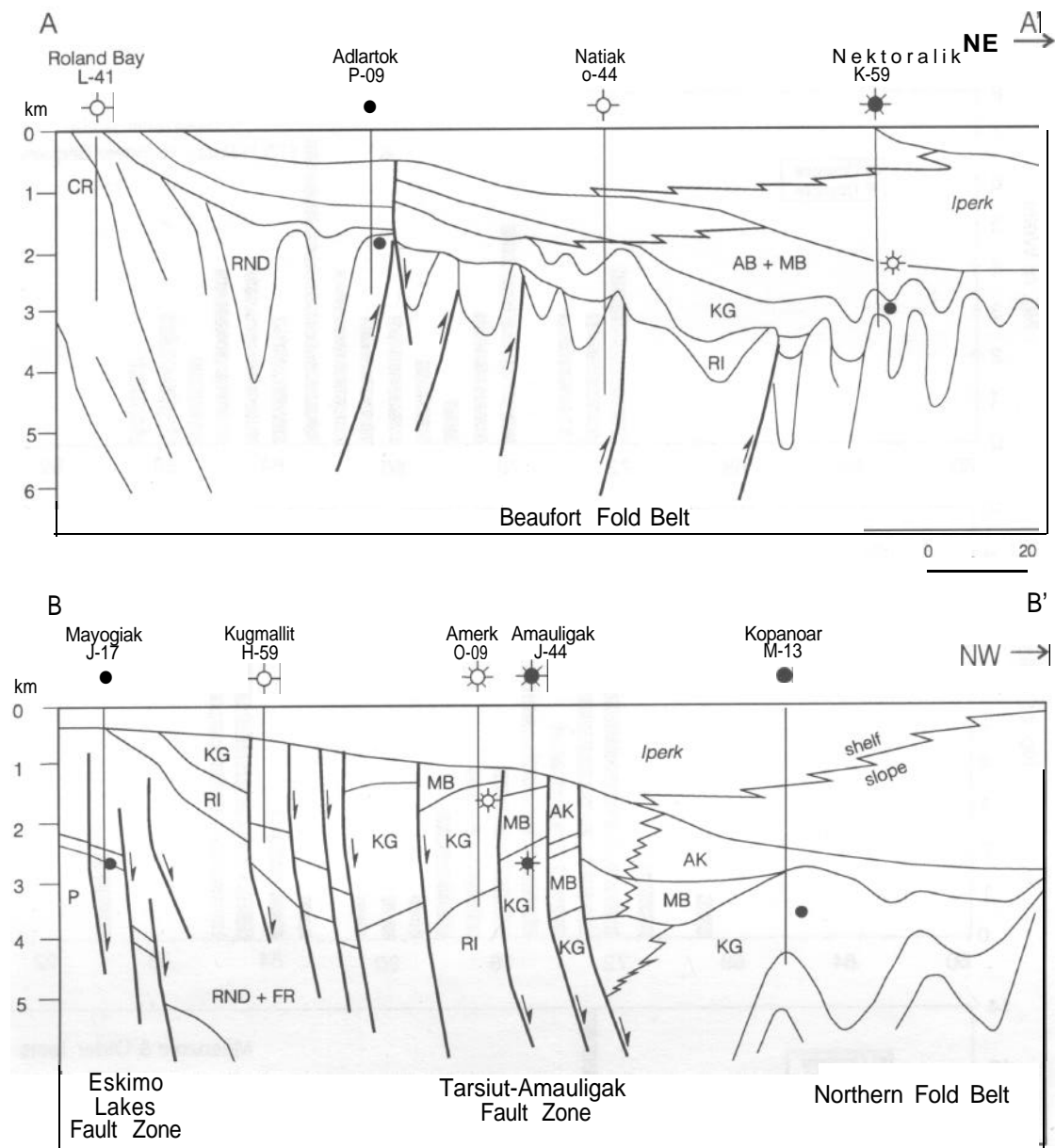


Figure 47. Schematic cross-sections, Beaufort-Mackenzie Basin (after Dixon et al., 1992). P-Paleozoic; CR-Cretaceous; FR-Fish River; RND-Reindeer; RI-Richards; KG-Kugmallit; MB-Mackenzie Bay; AK-Akpak.

structures evident on seismic lines and the possibility of more oil-prone source rocks. Success offshore at Kopanoar in 1976 was followed by a series of oil and gas discoveries culminating with Amauligak in 1983 by Gulf. Exploration declined towards the end of the decade although offshore discoveries continued to be made each year until 1989. Current exploration is focused onshore with the most recent discovery of oil and gas at Unipkat by Shell (1990).

The drilling of 183 exploratory wells in the Beaufort-Mackenzie region has resulted in 44 significant discoveries in Upper Cretaceous and Tertiary

strata plus a further nine in older rocks along the margins of the basin. Many of the larger discoveries were subsequently delineated. Tables 4 and 5 list all discoveries in the Beaufort-Mackenzie region, including discoveries in the Tertiary basin and in older strata.

Stratigraphy (Fig. 49)

Upper Cretaceous, and Tertiary to Recent sediments were deposited on the Beaufort Sea continental margin in 11 transgressive/regressive sequences. Successive

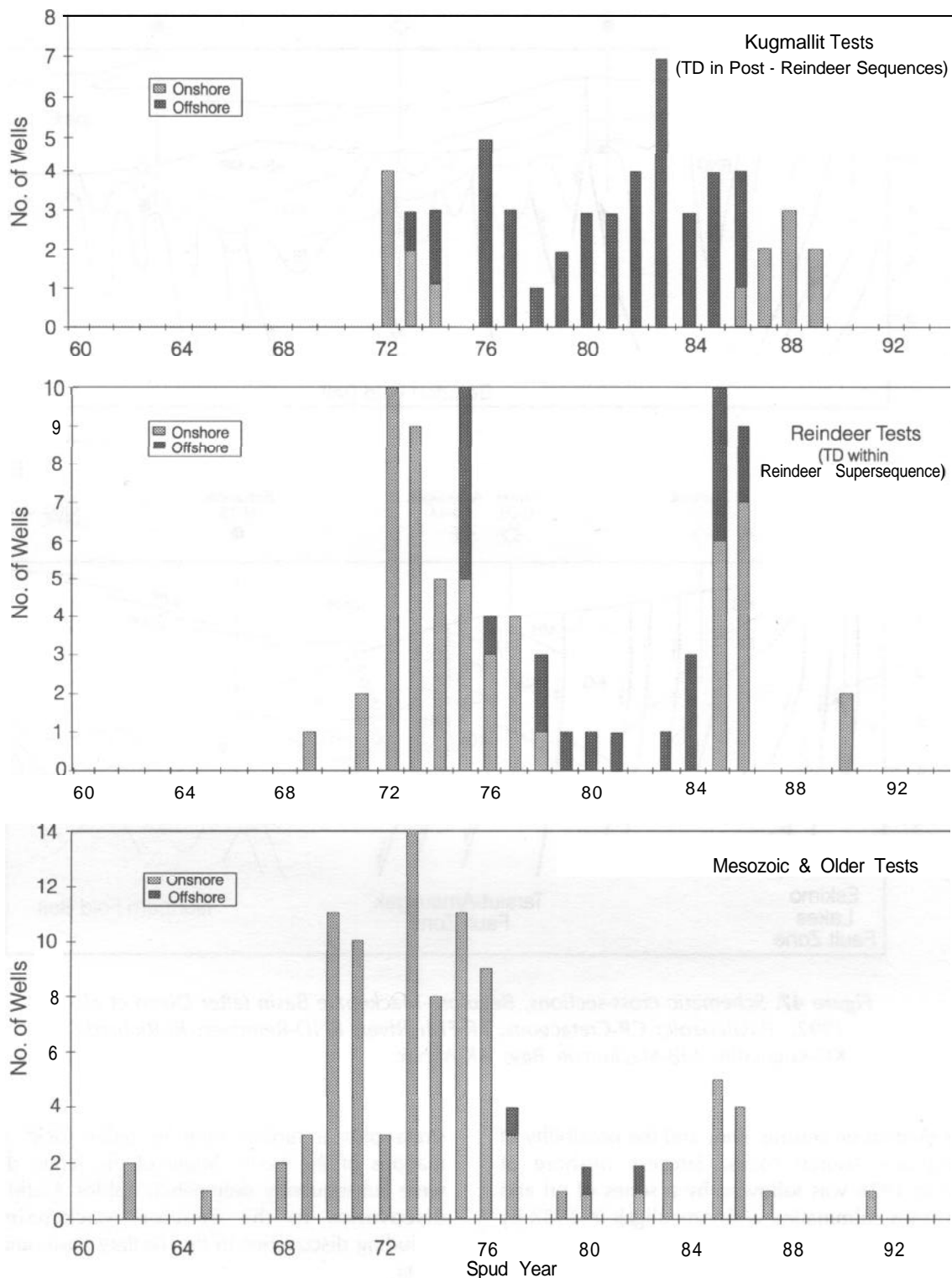


Figure 48. Drilling history, by year and geological objective; Beaufort-Mackenzie area.

SHELF BUILDING EPISODES IN THE MACKENZIE DELTA BASIN

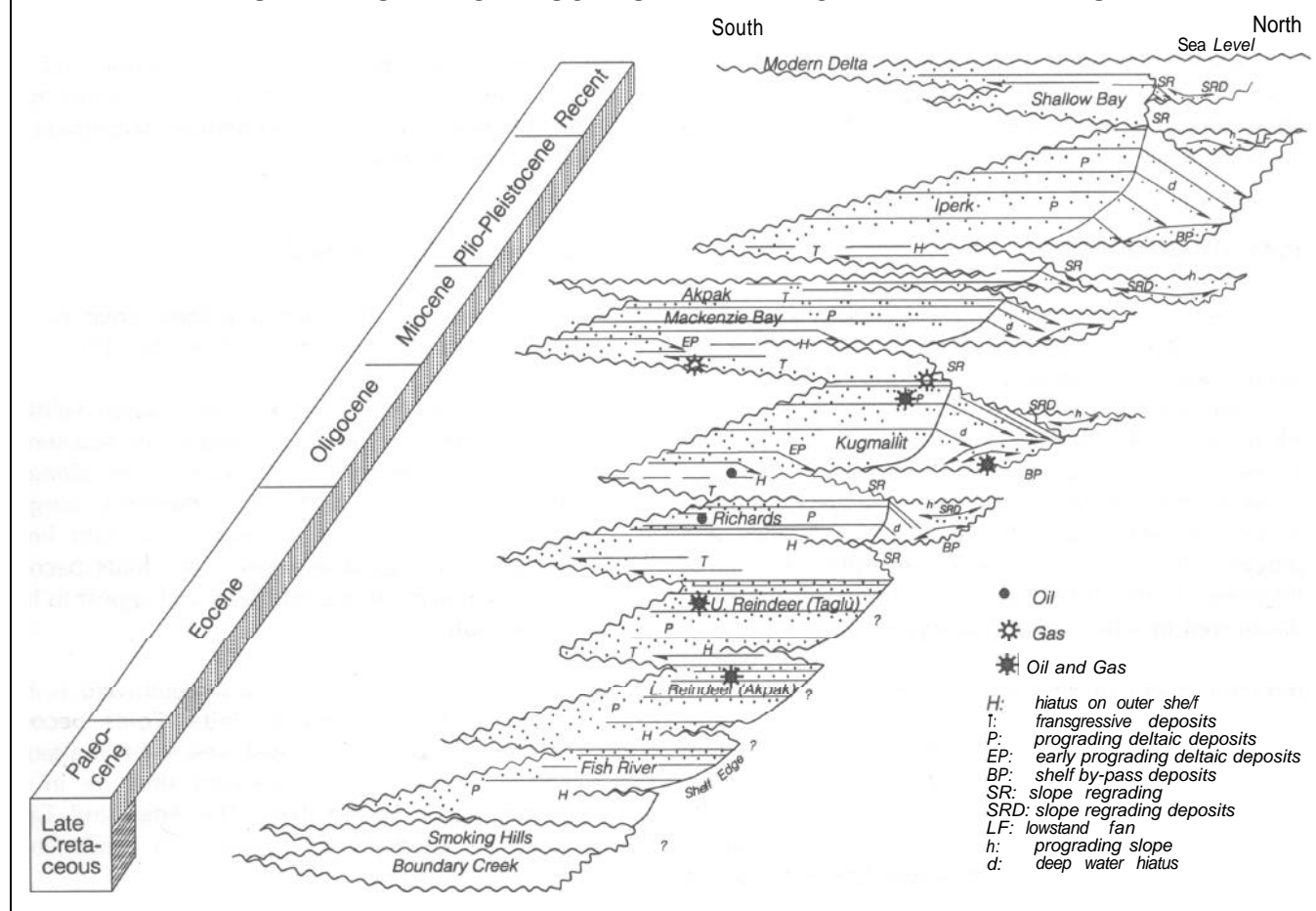


Figure 49. Schematic sequence stratigraphy, Beaufort-Mackenzie Basin.

deltaic pulses have caused the basin to build northwards across the continental margin onto oceanic crust, marked by the northward shift of the basin depocentre.

During the Late Cretaceous, sedimentation was limited to organic-rich muds in an outer shelf to basinal environment, with slight terrestrial input. These, the Boundary Creek and Smoking Hills sequences, are penetrated by wells in the southern Mackenzie Delta. From the end of the Late Cretaceous to the mid-Eocene, deltaic depocentres were located along the southwestern margin of the Canadian Beaufort Sea. The Fish River, Akpak and Taglu sequences, known from the subsurface of Richards Island and from outcrop on the Yukon Coastal Plain, were deposited during this period. Uplift of the Cordillera southwest of the region during the mid-Eocene shifted the basin depocentre to the central Beaufort. This new focus for deposition caused greater loading. The resulting subsidence has accommodated thick stacks of deltaic sediments – the Richards, Kugmallit, Mackenzie Bay, Akpak and Iperk

sequences. Together, these span the time from mid-Eocene to Plio-Pleistocene. The modern delta caps the Shallow Bay sequence. Deposition is occurring in much the same tectonic setting as for most of the late Tertiary.

In general terms, lithological composition, thickness, bounding conditions and depositional environments for each sequence vary systematically across the basin. Proximal delta-plain deposits grade northwards into delta-front, distal prodelta, shelf and slope and basinal deposits.

Models of depositional system architecture for cycles of transgression and regression predict the development of distinct depositional “systems tracts” at various stages of relative sea level. In the Beaufort Sea, highstand system tracts are relatively well understood (based on good well control) and form the basis for the published stratigraphic framework. Farther north, the stratigraphic relationships of strata penetrated by wells in the distal regions of the basin are not fully resolved.

Deposition of lowstand systems tracts (and of basin slope equivalents of highstand deposits) on the continental slope and basin floor is complex and not well understood with the current low density of well control. A better understanding of the lowstand stratigraphy is necessary for the further pursuit of turbidite reservoirs in the deeper parts of the basin.

Potential Reservoirs

All sandstones in post-Upper Cretaceous sequences have potential as reservoirs but discoveries have not been made in sequences above the Miocene. The principal reservoir units are the Paleocene to Eocene Aklak and Taglu sandstones in the west Beaufort and beneath Richards Island, and the Kugmallit sandstones in the central offshore. These deltaic sequences consist of interbedded delta-front/delta-plain sandstones and prodelta shales that can reach over 1000 m in gross thickness. In the distal parts of the basin, oil has been discovered in a thin limestone representing a hiatus in clastic input (and a sequence boundary), but this type of reservoir is not of volumetric significance.

The Amauligak discovery is in a typical delta-front sequence of the Kugmallit. Net pay of 400 m is distributed between 38 stacked sandstones separated by shales, over a vertical interval of 1500 m. Lateral continuity of delta-front sands across the width of the structure appears good on the basis of delineation drilling. Porosity averages 24%, ranging up to 33%, with permeability enhanced by pervasive development of secondary porosity. Distal slope and basin equivalents of the Kugmallit, as encountered at Kopanoar, are thick sequences of interbedded turbidite sandstones deposited in a lower to mid-fan environment. Log porosity ranges from 12 to 15%, probably averaging across thin beds of variable reservoir quality.

Reservoirs of Eocene and older sequences tend to have higher percentages of volcanic fragments than the younger sequences, are better cemented and exhibit lower porosity, in the range 12 to 20%. At Taglu field, three series of stacked channel sandstones at the top of the Taglu sequence are gas bearing: these total 130 m of net pay out of a gross interval of 600 to 700 m.

Delta-front sandstones of the Early Eocene Aklak sequence drilled at Adlartok in the west Beaufort have variable porosity and permeability dependent on grain size. The better reservoir beds have porosity in the range 20 to 24%, but this drops to 15 to 18 % in the finer grained, laminated units.

Oil, heavy oil and gas have been discovered in sandstones of the Taglu sequence along the flank of the Tuktoyaktuk Peninsula near the southeastern edge of the basin. These deposits are very shallow and the deltaic sandstones that host the accumulations have retained high porosity. Lateral continuity of reservoirs in this area appears poor.

Structure, Traps and Seal

The basin can be subdivided into three areas on the basis of dominant structure (see Figs. 46, 47).

- (1) In the western Beaufort Sea, the Beaufort Foldbelt extends from northeastern Alaska to the Mackenzie Delta in a broad arc. Structures are elongate anticlines cut by high-angle, northerly verging thrust faults, resulting in asymmetric fold limbs (Adlartok is a good example). The folds become more symmetric to the northeast and appear to lack thrust faults.

The orientation of fold axes turns southward as they approach the Mackenzie Delta. Folds become increasingly cross-cut by east-west extension faults, which become the predominant structure in the central region of the delta. The Adgo and Taglu structures exemplify this change in predominant structural influence.

- (2) The Mackenzie Delta and central Beaufort Sea is underlain by an extensional regime of listric faults and associated tilted fault blocks typified by the Tarsiut-Amauligak Fault Zone. The faulting is perpendicular to the direction of sediment input to the basin with the majority of faults down-thrown to the north creating a stepwise series of tilted fault blocks. Many of the faults have large throws (in the order of thousands of metres) with thickened deposits on the foot wall. There is a long history of movement on most of these faults but faulting appears to have ceased in the late Miocene.

Farther inshore, and confined to the older sequences, the larger listric faults are supplemented by faults of shorter radius, which may be more directly associated with individual deltaic progradations.

- (3) In the eastern Beaufort Sea and under the continental rise of the Canada Basin, the basin is relatively undeformed. Extension faults with large throws occur along an inner zone (the Eskimo

Lakes Fault Zone and its northeastern offshore extension) and an outer zone (the outer hinge line), which is the northeastern extension of the Taglu Fault Zone. Ukalerk is an example of this type of structure.

Source Rocks

One Upper Cretaceous and four Tertiary units are considered source rock candidates for oil and gas in the basin. The Boundary Creek/Smoking Hills sequences are rich in marine organic matter with TOC ranging from 2 to 10%. These are rich potential sources of oil, but appear to have contributed little to hydrocarbons in Tertiary reservoirs, particularly in the offshore parts of the basin where the unit may be absent or over-mature.

Potential source rocks in the Tertiary occur in prodelta shales of the Richards and Kugmallit sequences. Although terrestrial organic matter predominates, oil-prone kerogen is present in the form of resinite, which generates oil at low levels of maturity. Organic matter is not concentrated in the prodelta depositional environment and TOC seldom exceeds 2%. However, source rock intervals are thick and enter a high-gradient transition zone into maturity below about 4000 m. The wide variation in depth of burial across the fault blocks in the area causes potential source rocks to reach temperatures sufficient for oil and gas generation in down-dip regions of tilted fault blocks and, locally, in grabens within the Tarsiut-Amauligak Fault Zone. That large volumes of oil and gas have been generated from Tertiary source rocks is demonstrated by

the Amauligak discovery where the Tertiary origin of the oils has been confirmed by biomarker studies.

Oils from the Tertiary reservoirs are good quality crudes in the range 25 to 35 ° API with low pour points. Significant volumes of condensate are associated with the onshore gas discoveries.

Potential (Fig. 50)

The discovery record indicates good potential for oil and gas both offshore and onshore. The potential of the basin has been recently evaluated by the Geological Survey of Canada using probabilistic play analysis (Dixon et al., 1994). The analysis identified large potential resources of current interest in plays in the outer delta and shallow offshore environments, and in the offshore delta, principally in the Taglu and Kugmallit sequences. There is a good probability of finding additional pools with recoverable resources exceeding $28.3 \times E9 \text{ m}^3$ (1 tcf) of gas and of oil pools exceeding $15.9 \times E6 \text{ m}^3$ (100 million barrels), together with larger numbers of smaller pools in satellite fault blocks and structural stratigraphic traps.

The onshore delta underwent an early reconnaissance phase of exploration, which resulted in large gas discoveries and some minor associated oil discoveries. The potential for more substantial oil discoveries and supplementary gas discoveries is high and will be realized with a better understanding of structural complexity and depositional architecture, aided by new seismic exploration techniques.

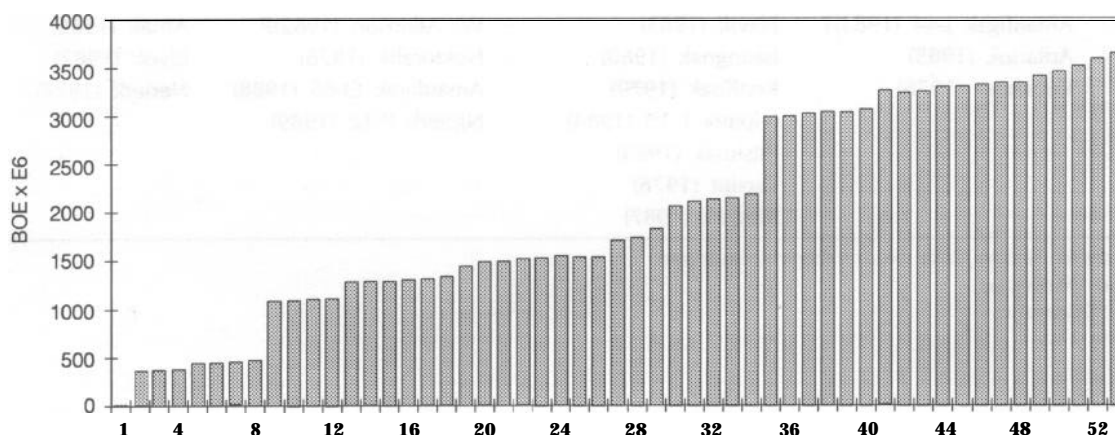


Figure 50. Cumulative discovered resources in millions of barrels of oil equivalent; Beaufort-Mackenzie area.

Table 4. Gas discoveries in the Beaufort-Mackenzie Region (bcf)

>2000 bcf	1000-2000 bcf	500-1000 bcf	100-500 bcf	10-100 bcf	<10 bcf
Taglu (1971)T	Parson (1971)K	Niglintagak (1972)	Adgo (1973) Garry N. (1975) Carry S. (1978) Hansen (1986) Tuk L-09 (1983) K YaYa S. (1972)	Ikhil (1986) Mallik (1972) Pelly (1974) Reindeer (1973) Titalik (1972) YaYa N. (1974)	
	Amauligak (1983) Issungnak (1980)	Kenalooak (1979)	Netserk (1975) Ukalerk (1977) Kingark (1987)	Amerk (1984) Amak (1986) Isserk (1977) Itiyok (1982) Kadluk (1983) Kiggavik (1982) Nektoralik (1976) Minuk (1985)	Nerlerk (1977)

Discoveries are in Tertiary units unless otherwise indicated

K = Cretaceous Discoveries

P = Paleozoic Discoveries

Table 5. Oil discoveries in the Beaufort-Mackenzie Region (mmbls)

500-100 mmbls	100-25 mmbls	25-10 mmbls	< 10 mmbls
Onshore	Atkinson Point (1969)K Ivik J-26 (1972) Adgo (1973) Kumak (1973) Unipkat (1990)	Garry P-04 (1975) Ivi k K-54 (1973) Imnak (1974)K Kugpik (1973)K Niglintgak (1972) Tuk J-29 (1985)	Kamik (1975)K Mayoigiak (1971)P
Offshore	Amauligak J-44 (1983)T Adlartok (1985) Kopanoar (1976)	Havik (1983) Issungnak (1980) KoaKoak (1979) Nipterk L-19 (1984) Pitsiulak (1983) Tarsiut (1978) Kingark (1987)	W. Atkinson (1982)P Nektoralik (1976) Amauligak O-86 (1988) Nipterk P-32 (1989) Arnak (1986) Itiyok (1982) Nerlerk (1977)

Discoveries are in Tertiary units unless otherwise indicated

K = Cretaceous Discoveries

P = Paleozoic Discoveries

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CHAPTER 5 – CANADIAN ARCTIC ISLANDS

BANKS BASIN

Age	Mesozoic over Paleozoic
Depth Target Zones	Maximum 3000 m to base Mesozoic; up to 2000 m Paleozoic
Hydrocarbon Shows	None
First Discovery	None
Basin Type	Unstable cratonic margin
Depositional Setting	Marine shelf to basin transitional (Paleozoic); fluvial, transitional and marine shelf (Mesozoic)
Potential Reservoirs	Mesozoic sandstones, Devonian Blue Fiord carbonates
Regional Structure	North-south series of highs with intervening subbasins, extension faulting, minor folding
Seals	Transgressive marine shales (Weatherall Formation), basinal shales (Eids Formation) and inter-tonguing marine shales in the Mesozoic section
Source Rocks	Eids shale and other basinal equivalents of lower Paleozoic shelf carbonates
Depth to Oil Window	Base of Mesozoic is transitional from immature into overmature Paleozoic sediments
Total Number of Wells	11 (onshore Banks Island)
Seismic Coverage	9200 km ² of reconnaissance seismic
Area	60,100 km ² (Banks Island)
Area under Licence	None

(Bare tundra, low relief terrain. Population centre at Sachs Harbour on southwestern Banks Island. Extreme winter operating conditions.)

Banks Basin contains a moderately thick Mesozoic section overlying a thick sequence of lower Paleozoic carbonates and basinal equivalents. Eleven wells have been drilled without success, but a number of exploration plays have been defined that have moderate potential, principally for gas. The basin is mostly onshore, but extends northwards across McClure Strait into Eglinton Craben where deeper burial of Mesozoic source rocks may improve oil potential.

Geological Setting (Figs. 51, 52)

Banks Basin is a longitudinal trough of Jurassic to Tertiary clastic sediments confined on the western side by the Storkerson Uplift, a horst of Mesozoic age, which parallels the rifted margin of the Canada Basin, and by the Prince Albert Homocline, composed of westward-dipping Paleozoic strata on eastern Banks Island and neighbouring Victoria Island. The basin is overlain by a thin Tertiary cover, which thickens to the west across the Arctic Coastal Plain and the continental shelf of the Beaufort Sea.

Exploration History

The first well on Banks Island, Elf Storkerson Bay A-I 5, drilled in 1971, tested the Tertiary and upper Mesozoic succession of the Arctic Continental margin west of the Storkerson Uplift. Banks Basin (sensu Miall, 1979) lies east of the Storkerson Uplift and has been tested by seven of the 11 wells drilled on the island. The most recent well, Chevron Muskox D-87, was drilled in 1982. Although no wells discovered hydrocarbons, several did encounter reservoir quality porous rock. Primary targets have been Paleozoic carbonates, with

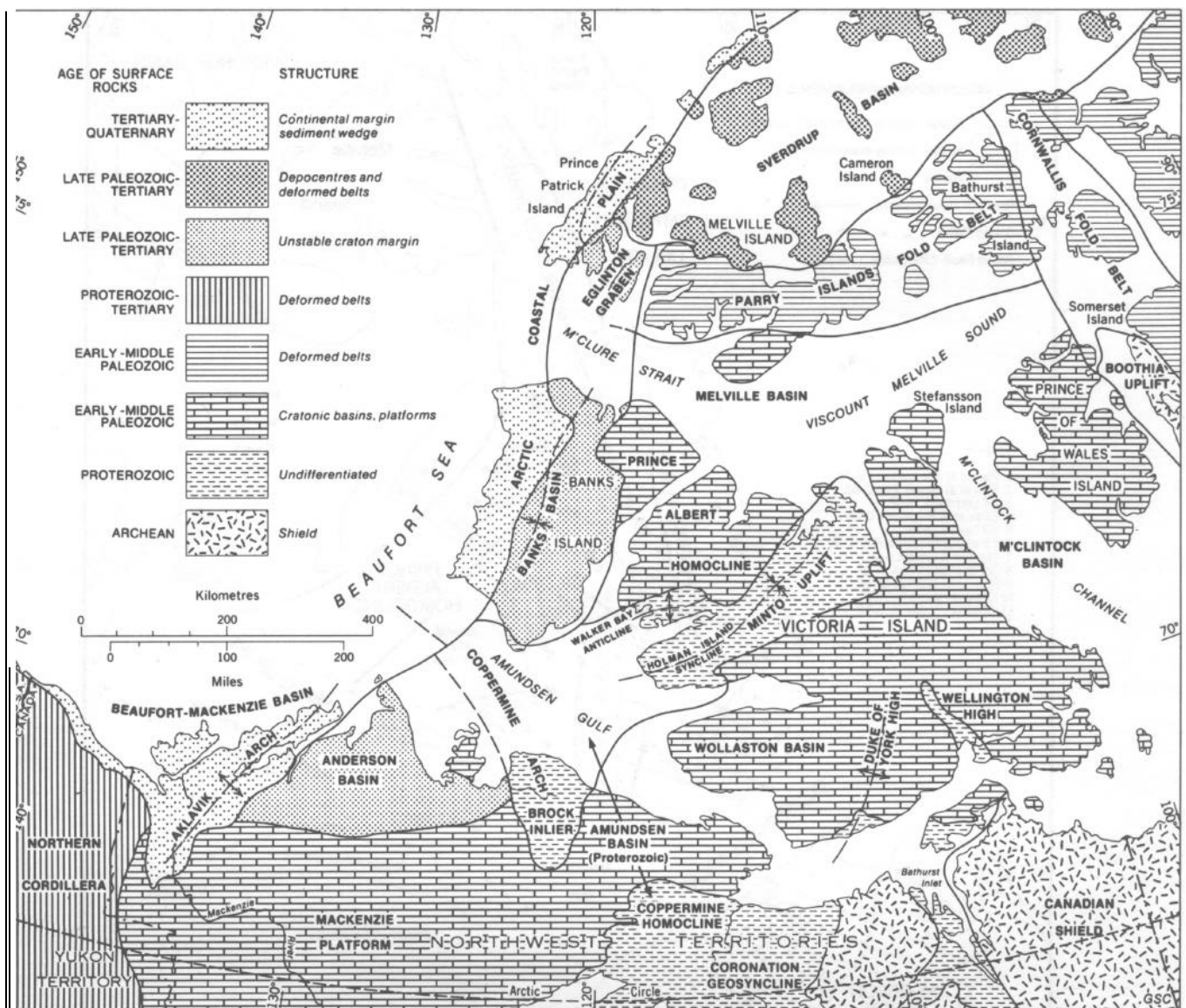


Figure 51. *Regional tectonic elements in the western Canadian Arctic (from Miall, 1979).*

sandstones in the overlying Mesozoic section a secondary objective.

Stratigraphy (Fig. 53)

For most of the early Paleozoic, the Banks Island region straddled a zone of major facies transition from carbonate shelf in the east to shale basin in the west. The older shelf facies are represented by dolomites of the Allen Bay-Read Bay formations, widely exposed on western Victoria Island (Late Ordovician to Late Silurian - approximately 1000 m in the Murphy et al. Victoria Island F-36 well), and by limestones of the Blue Fiord Formation (Early to Middle Devonian, 632 m in

Deminex-CGDC-FOC-Amoco Orkut I-44). The carbonate shelf is fringed by a chain of bioherms culminating in Blue Fiord reefs, which shared a contiguous environment of deposition with the productive reef in the Bent Horn oilfield on Cameron Island to the northeast. Between shelf and basin a slope carbonate facies has been recognized.

Melville Island Group clastics from a northern and northwestern hinterland in the late Middle Devonian superseded carbonate deposition in the region. The bulk of the Melville Island Group sediments are of deltaic origin with associated shallow marine and fluvial facies. An easing of clastic input to the basin in the Frasnian enabled growth of reefs of the Mercy Bay

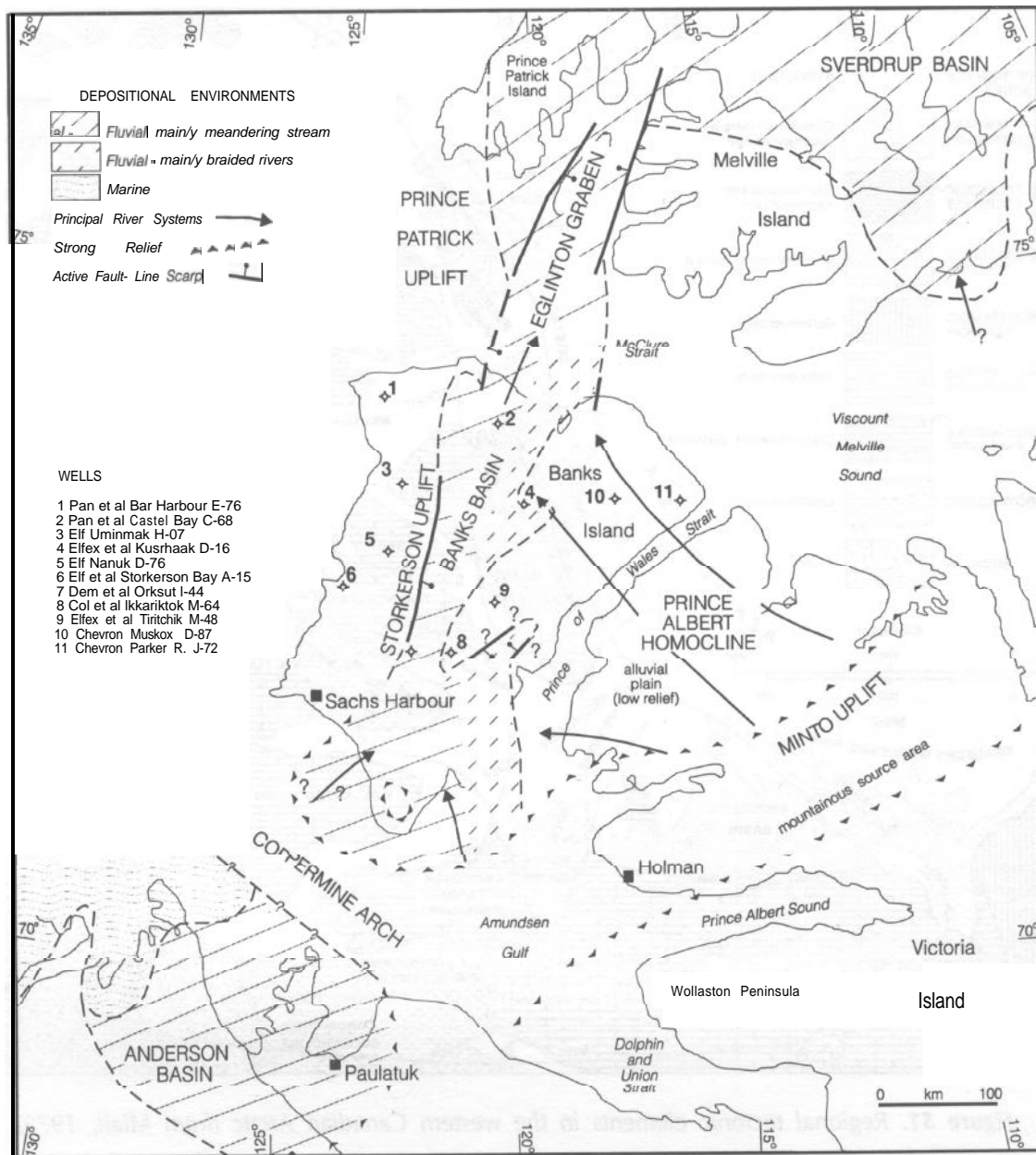


Figure 52. Mid-Early Cretaceous paleogeography, Banks Island area (from Miall, 1979).

Formation towards the end of Melville Group deposition.

Mesozoic strata overlie rocks of the Melville Island Group at a major stratigraphic break, which lasted from the Late Devonian to the Middle Jurassic. The oldest Jurassic formation is the Hiccles Cove Formation of the Wilkie Point Group, a thin shelf to shoreline sandstone preserved in the deepest parts of Banks Basin. Shales of the Mackenzie King Formation were deposited during the Early Cretaceous (356 m in Orksut I-44), later overstepped on the basin margins by thick fluvial sandstones of the Isachsen Formation (Hauterivian to Aptian, >200 m ?). The Isachsen Formation is variable

in thickness and texture and was deposited during a period of active uplift and rifting. Marine shales with local shoreline sandstones of the Christopher Formation were deposited during a period of regional transgression that culminated in the Cenomanian with the development of barrier island sandstones of the Hassel Formation. The Kanguk Formation, a basinal bituminous shale, was deposited from the Turonian to the Maastrichtian.

The Paleogene Eureka Sound Formation is predominantly fluvio-deltaic. Deposited across the breadth of the Arctic Coastal Plain, this formation is preserved in the shallow subsurface in Banks Basin. The

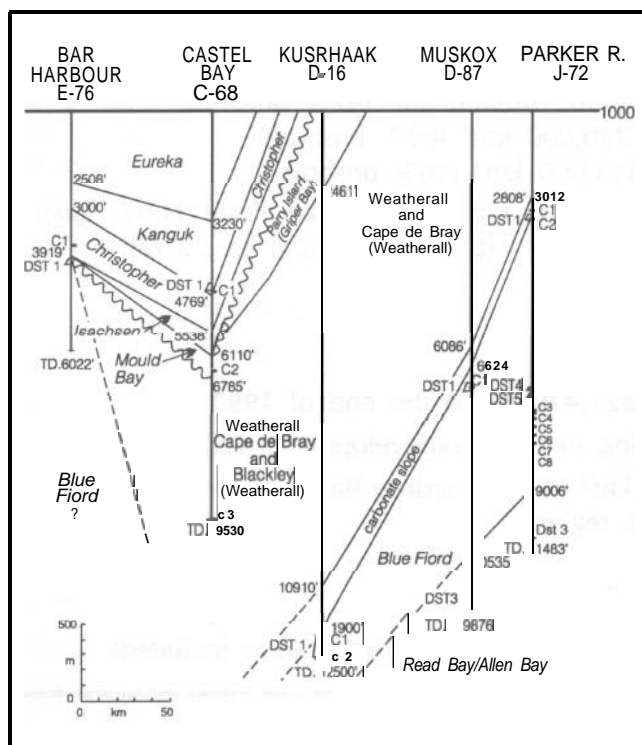


Figure 53. East-to-west cross-section through some of the Banks Island Wells.

younger Beaufort Formation is preserved as a thin veneer across the Arctic Coastal Plain, thickening progressively into the offshore.

Potential Reservoir

Devonian and older shelf carbonates and their associated bank edges define a fairway with good reservoir potential crossing Banks Island. Thick sections of porous rock have been encountered in the Blue Fiord Formation with pipe recoveries of formation water obtained from intervals in Panarctic Tenneco et al. Castel Bay C-68 and Chevron et al. Parker River J-62. The fluvial sandstones of the Isachsen Formation (and younger Mesozoic and Tertiary formations) are also potential reservoir rocks.

Structure, Traps and Seal

Early Paleozoic deposition occurred over a stable cratonic margin. Traps are related to facies transitions and carbonate build-ups with seal provided by overstepping basinal shales. The development of horst and graben topography in the mid-Mesozoic rifting episode created the possibility of structural traps in the Paleozoic and structural/stratigraphic traps in Mesozoic sandstone reservoirs. Seal is provided by marine shales within the Mesozoic succession.

Source Rocks

The overlying marine shales and downslope basinal equivalents of the Paleozoic carbonates have good potential as source rocks, given sufficient organic richness. However, based on spore coloration, the Paleozoic section is overmature (Miall, 1976). The Mesozoic section appears immature with the bituminous shales of the Upper Cretaceous never sufficiently buried to generate oil.

Potential

The major hiatus in the stratigraphic record represents an extended period of uplift and truncation, culminating in rifting in the Jurassic. Generation and migration of Paleozoic hydrocarbons is likely to have occurred prior to and during this period, lessening the possibility of preservation of accumulations in Paleozoic rocks.

Although several potential reservoirs are present, the distribution of porosity in the Paleozoic section remains uncertain. The majority of traps in the Paleozoic are stratigraphic and would require intensive seismic delineation. The overmaturity of the Paleozoic section, the absence of upper Paleozoic and Triassic source rocks known from the Sverdrup Basin, and the general lack of sufficient maturity in the Mesozoic section lessen the prospect of an oil play in this basin. However, the Paleozoic and the lower Mesozoic section retains a moderate potential for significant gas discoveries.

Acknowledgement

The above analysis of Banks Island potential has been taken, with some slight modification, from the report by Jefferson et al. (1988).

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ARCTIC ISLANDS: SVERDRUP AND FRANKLINIAN BASINS

Area	Arctic Stable Platform 780,000 km ² (47% onshore) Arctic Fold Belt 240,000 km ² (60% onshore) Sverdrup Basin 313,000 km ² (46% onshore)
Discoveries	First discovery in 1969 (Panarctic Drake Point N-67; gas): 18 subsequent discoveries (8 gas; 7 oil and gas; 3 oil)
Discovered Resources	Gas: 407 x E9 m ³ Oil: 66 x E6 m ³
Production	Gas: none Oil: Bent Horn 321,470 m ³ to the end of 1993
Total Number of Wells	177 (192 including delineation/development wells?)
Average Well Density	1 well per 1630 km ² in the Sverdrup Basin, 1 per 7000 km ² in the Arctic Islands region
Seismic Coverage	44,242 km
Pipelines	None
Area under Licence	13,000 km ² (or 37,500 km ² if restricted areas included)

Most northerly of Canada's exploration regions, the Arctic Islands overlie one of Canada's largest petroliferous basins. Exploration activity has been extensive, but sparsely distributed, across this huge region. Nevertheless, the 160 wells drilled to date have discovered gas resources (over 14 trillion cubic feet) equal to 20% of remaining reserves in western Canada, and two of the largest undeveloped gas fields in Canada are in the Arctic Islands. Exploitation of the oil resources of the region is already underway. Both gas and oil potential in this basin is very high and realizable given enhanced geological understanding and new exploration methods. It is likely that the vast resources of this region will become important to North America in the next century with the depletion of conventional resources in western Canada.

Geological Setting (Fig. 54)

Since the dawn of the Cambrian, deposition in the sedimentary basins of the Arctic Islands has extended the North American landmass some 1400 km seaward of the Canadian Shield and its skirt of Precambrian metasediments. The sedimentary column is divided into lower and upper sections characterized by more or less continuous subsidence and deposition, separated by major tectonic uplift – the Ellesmerian Orogeny – in the Late Devonian and Early Carboniferous. With this exception, the preserved strata span most of the Paleozoic, Mesozoic and early Tertiary.

The sedimentary strata, tectonic deformation and petroleum geology of the older pre-Ellesmerian section is discussed below under the title "Franklinian Basin". Post-Ellesmerian geology is discussed under the title of its successor, the largely superimposed "Sverdrup Basin". Finally, the geology underlying the Arctic Coastal Plain and extending under the waters of the

Arctic Ocean is discussed under the heading "Arctic Continental Terrace Wedge".

Exploration History (Figs. 55, 56)

The presence of extensive sedimentary basins with thick successions of Paleozoic and Mesozoic strata in the Arctic Islands, potentially favourable for oil and gas, was demonstrated in the 1950s by geologists of the Geological Survey of Canada (examples of the work of these earlier researchers are described in Fortier et al., 1954, and Thorsteinsson, 1958).

Exploration by petroleum companies began in the early 1960s. Most seismic exploration and drilling has occurred north of latitude 75°N, that is, in the Arctic Fold Belt and Sverdrup Basin. South of this latitude, exploration of the mildly deformed Paleozoic sequences of the Arctic Platform has been very sparse, with only three wells drilled (on Prince of Wales and

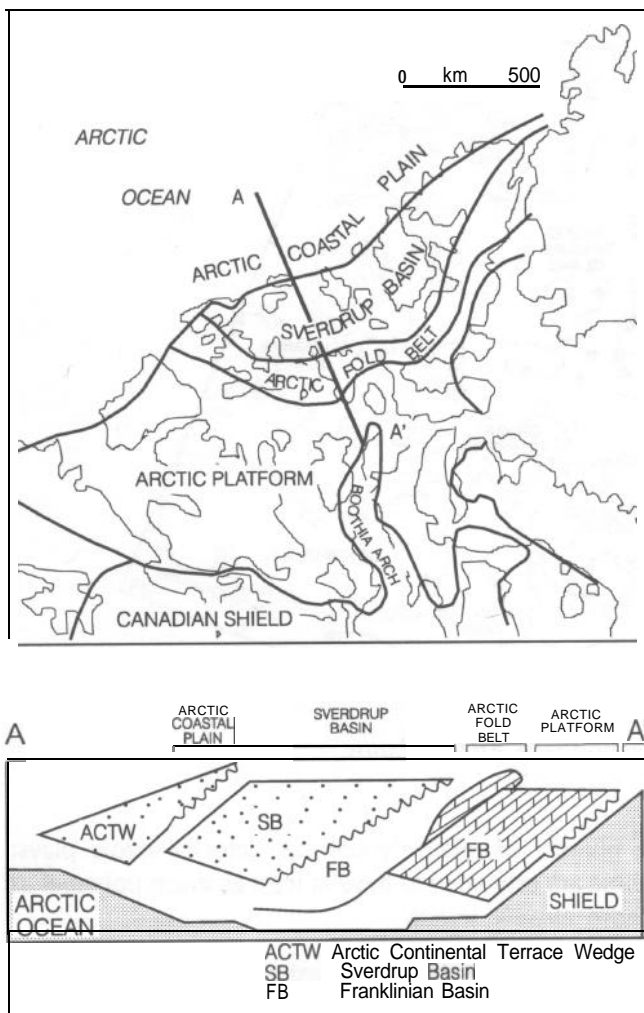


Figure 54. Tectono-stratigraphic elements of the Arctic Islands.

Somerset islands). The presence of the permanent ice cap and the extreme remoteness of the region have caused exploration of the Arctic continental terrace wedge to be equally limited.

The first Arctic Islands exploratory well was spudded in 1961 at Winter Harbour, Melville Island. Dome et al. Winter harbour No. 1 A-09 drilled Lower Paleozoic strata to a total depth of 3823 m. The well penetrated sandstones and siltstones of the Middle to Late Devonian clastic wedge in the up-hole section; these swabbed gas at low unsustained rates during a completion test. No hydrocarbons were tested from the thick carbonate section lower in the well and no significant porous zones were noted.

Since the drilling at Winter Harbour, a total of 19 discoveries have been made; three oil, 12 gas, and five

oil and gas. Discoveries of oil alone have tended to be small with the larger accumulations containing gas, or gas with associated oil. The offshore discovery at Cisco is an exception: the large proportion of oil to gas found in this structure holds promise for other oil accumulations in the large and major categories. Discoveries are listed in Table 6 and the cumulative discovery curve (in barrels of oil equivalent) shows no diminution of discovery size with exploration to date (Fig. 57).

In the early 1970s, industry turned to the north coast of Melville Island where thick Mesozoic sequences were known to be present in the Sverdrup Basin. Panarctic Drake Point N-67 well, drilled in 1969 to 2577 m on the Sabine Peninsula of Melville Island, was the first major discovery in the Arctic Islands. This giant gas field has been delineated by 14 wells, (including the discovery well and two relief wells drilled to control blowout of the discovery well). The delineation program discovered a major offshore extension to the field at East Drake I-55. Combined resources in the main Drake Point pool and the East Drake extension are quoted by the Geological Survey at $98.5 \times E9 \text{ m}^3$ (3.5 tcf). A second giant gas field was discovered soon afterwards at Hecla, 50 km along structural trend to the west of the Drake Point Field. In 1978, the smaller Roche Point gas discovery was drilled north of Hecla and just offshore of northwest Sabine Peninsula.

Early in their exploration program, Panarctic Oils Ltd. pioneered drilling offshore locations from artificially thickened sea ice. This proved an economic and efficient way of testing the numerous offshore structures in the central Sverdrup Basin, which lie in water depths of up to 500 m. A succession of discoveries followed near Lougheed Island, on the southwestern coast of Ellef Ringnes Island, on King Christian Island, and in the intervening waters. The first of these discoveries by Panarctic in the central Sverdrup Basin was King Christian in 1970, followed by Thor, Kristoffer, Jackson Bay, Whitefish, Char, Balaena, Cisco, Skate, Maclean, Sculpin, Cape Macmillan and finally Cape Allison in 1985. Dome and partners added Wallis to the tally in 1973.

Over this period, drilling also continued along the southern margin of the basin with success at Bent Horn on Cameron Island in 1974. This is the sole discovery in Paleozoic carbonates of the Franklinian Basin. It is also the only discovery in the Arctic Islands under production.

Drilling in the far northwest of the Sverdrup Basin on the Fosheim Peninsula also had limited success, recording a single discovery by Panarctic at Romulus.

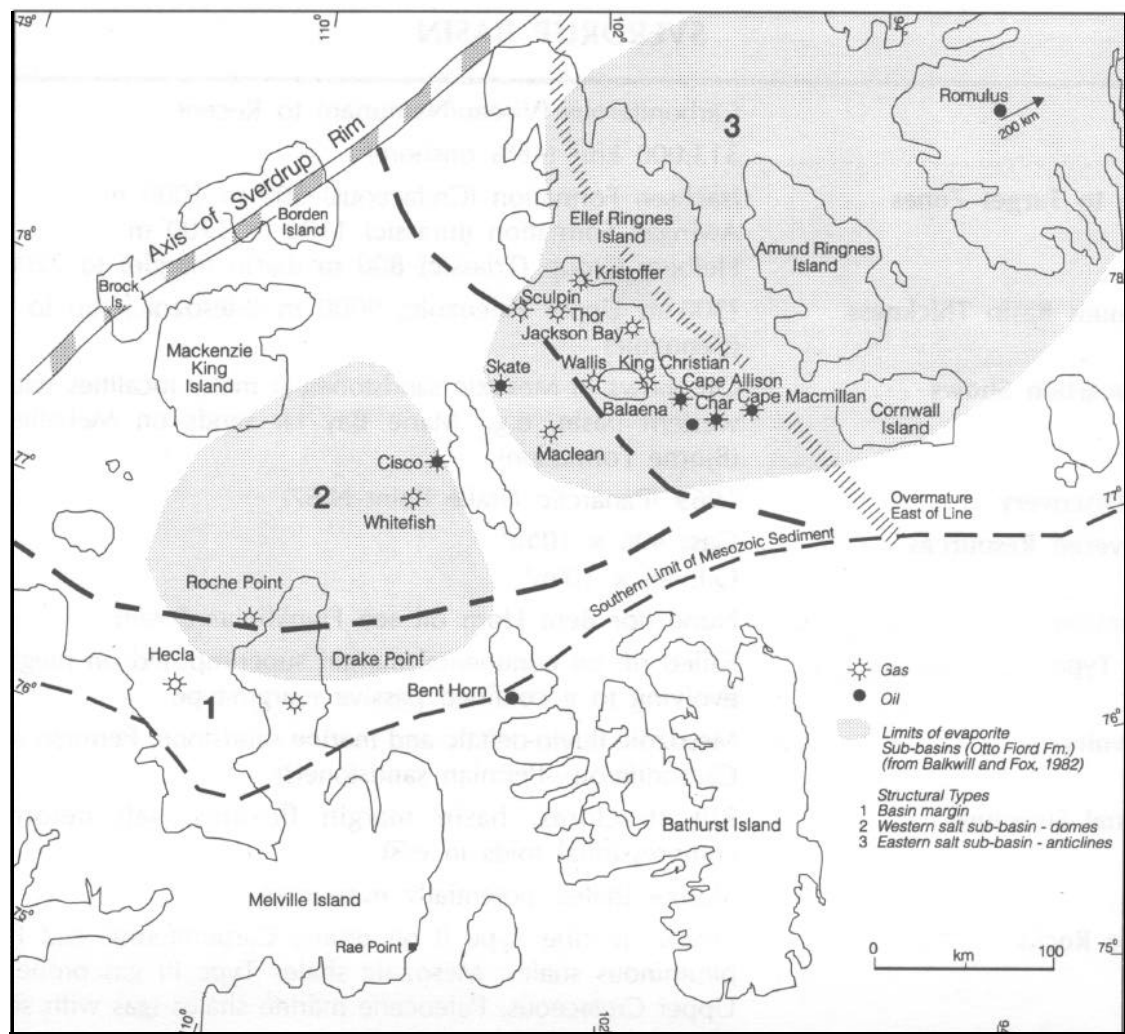


Figure 58. Tectonic elements of the Sverdrup Basin.

The northwestern margin of the developing basin was sub-parallel to the developing rift system. Horsts and grabens developed along this "Sverdrup Rim" was consistently less than in the basin depocentre. Since the inception of Mesozoic-Cenozoic spreading in the Canada Basin, the Sverdrup Rim has remained structurally high, more or less effectively separating the Sverdrup Basin from the Arctic Ocean.

The Sverdrup Basin was a major depocentre through much of the late Paleozoic and Mesozoic. Rapid subsidence, initiated by rifting in the Carboniferous and Early Permian, was followed by thermal subsidence at a more sedate rate, in passive margin fashion. From the Late Jurassic to the mid-Cretaceous, subsidence rates and deposition in the basin were influenced by events leading to the rifting and formation of new oceanic crust in the Canada Basin to the northwest. Widespread volcanism in the northern part of the Sverdrup Basin in

the mid-Cretaceous coincides with the main rifting in the proto-Canada Basin, and occurs where the north-northeast-striking late Paleozoic rifts of the Sverdrup Basin intersect the northeasterly trending rifted margin of the Canada Basin.

The early Paleogene saw the growing influence of orogenic events in the east coupled to the widening of the northern North Atlantic, and, in particular, to accommodate sea-floor spreading in Baffin Bay. The Eurekan Orogeny folded the eastern half of the Sverdrup Basin, much of which is uplifted and exposed on Ellesmere Island. The influence of this compression affected strata as far west as Lougheed Island. In the western Sverdrup Basin, subsidence continued as a result of differential loading of Carboniferous salt and the development of diapir fields. However, during the Tertiary, the focus of deposition shifted west to the Arctic Continental Terrace Wedge, beyond the confines of the Sverdrup Basin.

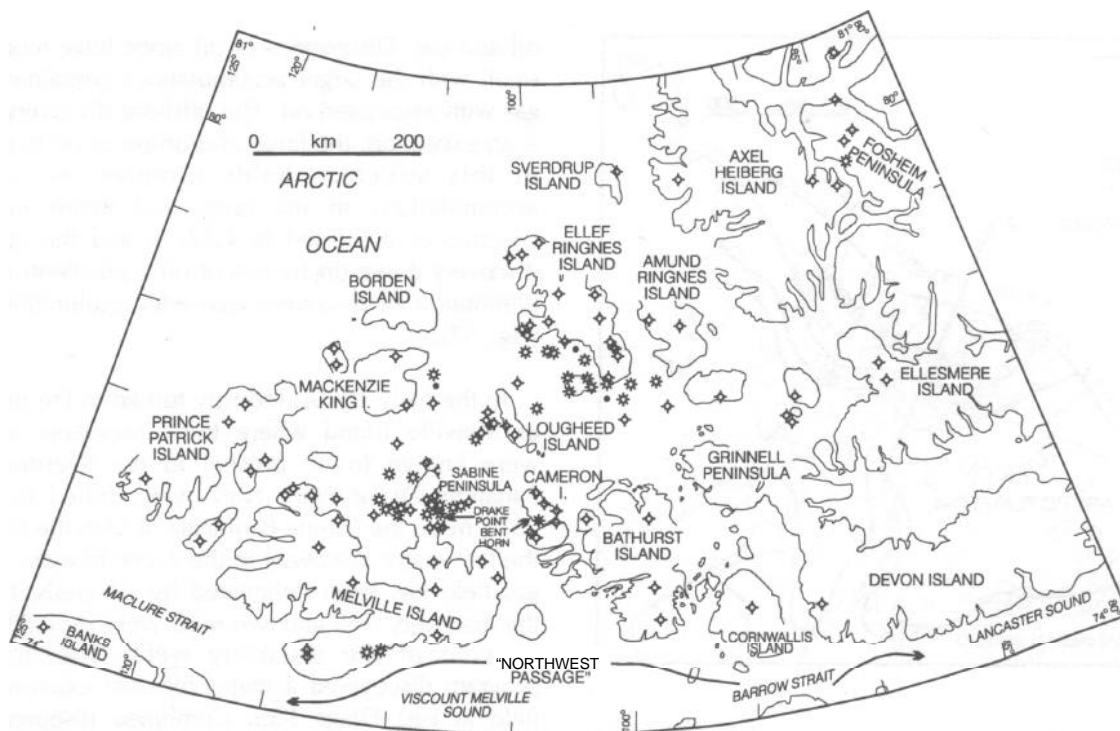


Figure 55. Well locations in the northern Arctic Island

Oil and condensate of various gravities and some gas were tested from Triassic and Jurassic sandstones. Although good to excellent permeability was inferred from several of the drillstem tests, pressure declines indicated reservoirs of limited extent and productive capability. The eight other wells drilled in this part of the basin were unsuccessful.

Following the peak drilling year of 1973 when 37 wells were drilled, drilling declined precipitously to a mere four wells in 1980. The early 1980s saw some recovery as companies worked new exploration licences across the basin. However, drilling continued to decline through the mid-eighties with the last exploratory well spudded in 1986. Panarctic unsuccessfully sidetracked an existing delineation well to further delineate the Bent Horn pool in 1987. Since that time, the basin has seen no exploration activity and has been ignored despite its potential for further major discoveries.

Outlook

The Geological Survey of Canada estimates the potential of the Arctic Islands at 686 x E6 m³ oil and 2257 x E6 m³ gas (average expectation). Both gas and oil potential are highest in the Sverdrup Basin, in both Mesozoic and late Paleozoic rocks. Future exploration may target deeper parts of the Mesozoic succession and

a number of relatively untested late Paleozoic plays: these are estimated to have at least as much potential as those already tested.

Although much of the past exploration focus (and success) has been in the central Sverdrup Basin, future efforts may target the southern rim of the basin and the Arctic Fold Belt. The Bent Horn field lies within this latter region of structural complexity and there is considerable potential along this trend. More importantly, relative proximity to shipping lanes through the Northwest Passage make exploitation of discoveries along the southern rim of the Sverdrup Basin a more economically attractive proposition.

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. Although development costs are high, resources discovered per metre drilled have been greater in the Arctic than in western Canada. Transportation cost, not petroleum potential, is clearly limiting the development of this remote region. In the late 1970s, various routes for a gas pipeline to southern Canada were studied and abandoned (Polar Gas Pipeline Project). Liquefaction and shipping of gas from Sabine Peninsula was also considered as an alternative to an extremely long and costly pipeline (Arctic Pilot Project). Tanker transport of oil, and possibly of liquefied natural gas certainly command greatly superior economics to any pipeline

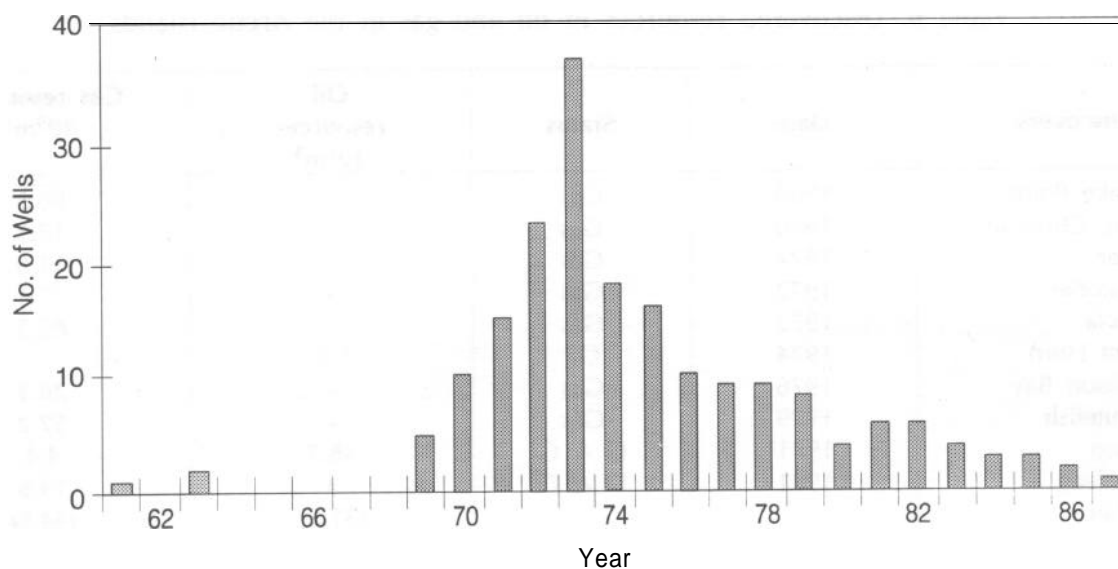


Figure 56. *Drilling history, Arctic Islands.*

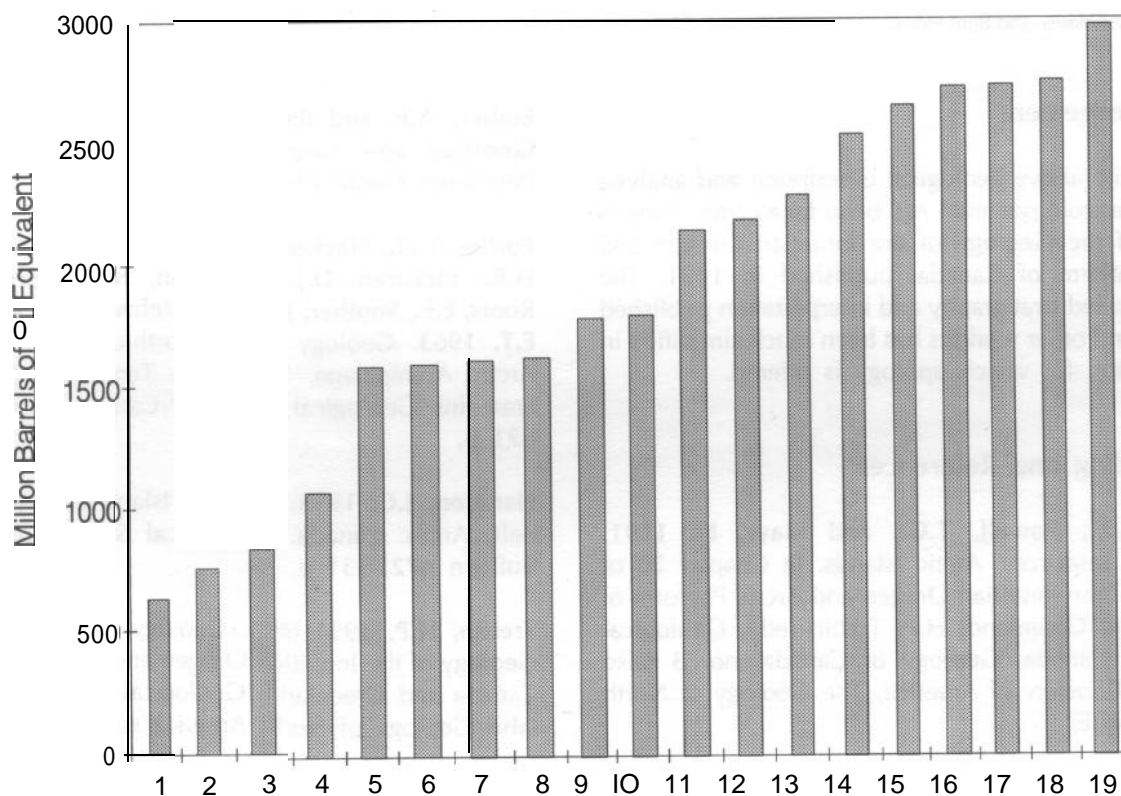


Figure 57. Cumulative discovered resources in the Arctic Islands by sequence of discovery.

project and allow for increments to supply without the major market perturbation inevitable with new supply from a large capacity pipeline. Further oil development awaits the discovery of new fields along the southern

margin of the basin, and for gas exploitation, the capability of major gas consuming countries to greatly expand their ability to import LNG.

Table 6. Discovered resources of oil and gas in the Arctic Islands

Discovery	Date	Status	Oil resources E6 m ³	Gas resources E9 m ³
Drake Point	1969	Gas		98.5
King Christian	1970	Gas	-	17.3
Thor	1972	Gas		11.9
Kristoffer	1972	Gas	-	27.1
Hecla	1972	Gas		85.5
Bent Horn	1974	Oil	1.0	
Jackson Bay	1976	Gas		28.3
Whitefish	1979	Gas		57.2
Cisco	1981	O & G	48.7	4.4
Maclean	1981	O & G	3	13.6
Other			(31.5)	(44.6)
	TOTAL	=	66	406 (14.3 tcf)

Notes: Discoveries in the category "other" include Romulus (1972, oil), Wallis (1973, gas), Roche Point (1978, gas), Char (1980, oil and gas), Balaena (1980, heavy oil), Skate (1981, oil and gas), Sculpin (1982, gas), Cape MacMillan (1983, oil and gas), and Cape Allison (1985, oil and gas).

Source: GSC (1983) for individual fields; NEB (1994) for "other" and basin totals includes unpublished revisions to discovered resource estimates and Bent Horn.

Acknowledgement

Much of the above geological description and analysis of the Paleozoic potential has been taken from various authors of the Geology of the Innuitian Orogen and Arctic Platform of Canada, published in 1991. The highly detailed stratigraphy and interpretation published by these and other workers has been much simplified in this account, for which apology is offered.

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SVERDRUP BASIN

Age	Carboniferous (Viséan/Namurian) to Recent
Area	313,000 km ² (46% onshore)
Depth to Target Zones	Isachsen Formation (Cretaceous) 500 to 1000 m Awingak Formation (Jurassic) 1100 to 1700 m Heiberg Group (Triassic) 800 m (basin margin) to 2200 m
Maximum Basin Thickness	1300 m Upper Paleozoic; 9000 m (Mesozoic); up to 300 m (Cenozoic)
Hydrocarbon Shows	Oil shows in Mesozoic sandstones at many localities within the western basin, e.g., Marie Bay tar sands on Melville Island (Bjorne Formation)
First Discovery	1969 (Panarctic Drake Point N-67)
Discovered Resources	Gas: 406 x E9 m ³ Oil: 65 x E6 m ³
Production	None (for Bent Horn oil see Franklinian Basin)
Basin Type	Failed rift on continental margin superimposed on megasuture, evolving to a confined passive margin-type
Reservoirs	Mesozoic fluvio-deltaic and marine sandstone; Permian reefs (?); Carboniferous-Permian sandstone(?)
Regional Structure	Rift structures, basin margin flexures, salt deformation, compressional folds in east
Seals	Marine shales, potentially evaporites
Source Rocks	Triassic marine Type II oil prone; Carboniferous and Permian bituminous shales; Mesozoic shales Type III gas prone Upper Cretaceous, Paleocene marine shales (gas with some oil potential but barely mature)
Depth to Oil/Gas Window ...	Variable
Total Number of Wells	160 exploratory and delineation wells
Average Well Density	One well per 1630 km ²

Geological Setting (Fig. 58)

The Sverdrup Basin overlies the central and distal Franklinian Basin with angular unconformity. The basin depocentre is displaced northwest and outboard (relative to the North American craton) of its predecessor and may overlie a plate suture of Ellesmerian vintage now incorporated within the North American continental margin. Northwest of the basin axis, the basin shallows onto the Sverdrup Rim, a zone of thickened continental crust that borders the Arctic Ocean. The Sverdrup Basin is about 1300 km along a northeast-southwest axis, and up to 400 km wide. The axial region contains up to 3 km of upper Palaeozoic

strata, up to 9 km of Mesozoic strata, and locally more than 3 km of uppermost Cretaceous and Tertiary strata.

Inception of the Sverdrup Basin followed the relaxation of Ellesmerian compression and uplift in the Arctic Islands in the early Carboniferous. An incipient rift system developed under extension, which struck north-northeast across the western Arctic Islands. The east-west striking Parry Island Fold Belt - the culminating feature of the Ellesmerian Orogeny - formed the southern terminus of this rift system. Normal faults, predominantly down-to-basin, parallel the earlier compressional structure along this margin.

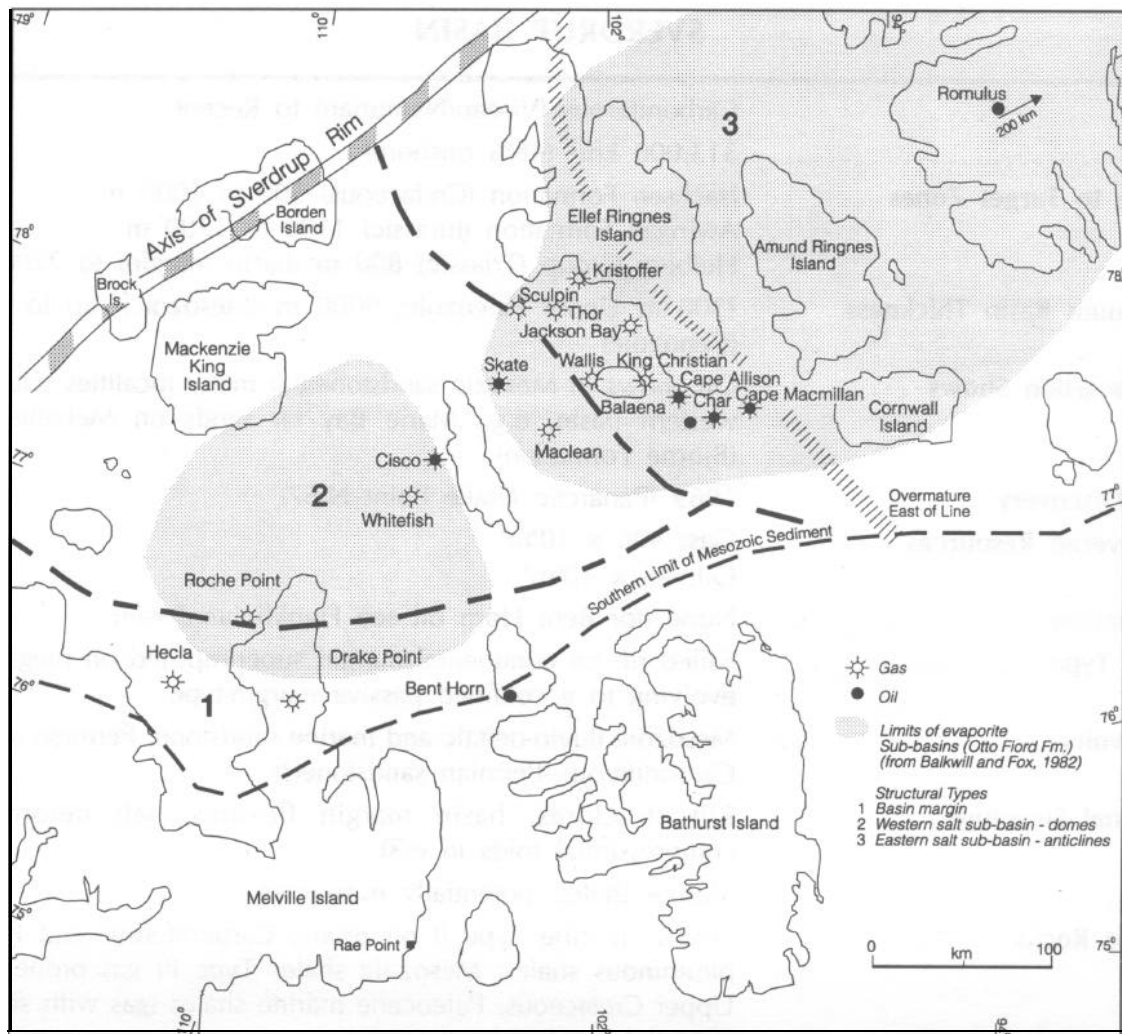


Figure 58. Tectonic elements of the Sverdrup Basin.

The northwestern margin of the developing basin was sub-parallel to the developing rift system. Horsts and grabens developed along this margin, but overall subsidence along this "Sverdrup Rim" was consistently less than in the basin depocentre. Since the inception of Mesozoic-Cenozoic spreading in the Canada Basin, the Sverdrup Rim has remained structurally high, more or less effectively separating the Sverdrup Basin from the Arctic Ocean.

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the mid-Cretaceous coincides with the main rifting in the proto-Canada Basin, and occurs where the north-northeast-striking late Paleozoic rifts of the Sverdrup Basin intersect the northeasterly trending rifted margin of the Canada Basin.

The early Paleogene saw the growing influence of orogenic events in the east coupled to the widening of the northern North Atlantic, and, in particular, to accommodate sea-floor spreading in Baffin Bay. The Eurekan Orogeny folded the eastern half of the Sverdrup Basin, much of which is uplifted and exposed on Ellesmere Island. The influence of this compression affected strata as far west as Lougheed Island. In the western Sverdrup Basin, subsidence continued as a result of differential loading of Carboniferous salt and the development of diapir fields. However, during the Tertiary, the focus of deposition shifted west to the Arctic Continental Terrace Wedge, beyond the confines of the Sverdrup Basin.

Stratigraphy (Fig. 59)

The earliest post-Ellesmerian strata in the Arctic islands belong to the Emma Fiord Formation of Early Carboniferous age. This formation of lacustrine shales, rich in alginite and characterized as "oil shale" at outcrop, may be of limited distribution in the subsurface. Much more widespread around the margins of the developing basin, and possibly within the deeply buried rifts of the basin are the red beds, sandstones and conglomerates of the Borup Fiord and Canyon Fiord formations. Of Late Carboniferous to Early Permian age, these formations mark an early phase of rapid subsidence in the basin. The sediments were derived from beveling of the basin rims and the local erosion of horsts within the basin and were deposited in an arid continental setting. Coevally with clastic deposition around the basin margins, evaporites of the Otto Fiord Formation were being deposited in two main depocentres along the axis of the basin, roughly east and west of the modern Lougheed Island. These thick Upper Carboniferous salts – halite predominates – mark the first marine incursions into the developing rift.

As marine influence increased in the Late Carboniferous and Early Permian, thick marine limestones of the Nansen and Belcher Channel formations were deposited in the northern and eastern basin and (more thinly) across the Sverdrup Rim. Reef growth occurred along the rims of the carbonate shelf. Argillaceous limestones and shales (Hare Fiord Formation) replaced evaporites in the central basin.

In the Late Permian, the shales and siltstones of the van Hauen Formation were deposited across the basin, marking the end of carbonate deposition. Sandstones of the Sabine Bay, Assistance Bay and Troid Fiord formations are proximal equivalents and suggest progradation from the northeast. Limestones of the Degerbols Formation are distal equivalents of the Troid Fiord sandstones. The retreat of carbonate deposition towards the east during the Permian and the growing predominance of sandstone/shale deposition across much of the western Sverdrup Basin may partly reflect the growing regional influence of uplands to the northwest and northeast of the Sverdrup Basin and partly the drift of the basin into more northerly paleolatitudes.

The Permo-Triassic boundary is marked by an unconformity at the basin margins, but was probably conformable across much of the basin as a shale-on-shale transition. Sandstones of the Bjorne Formation (Lower Triassic) were the first major incursion of coarse clastic deltaic systems in the basin. During this period sandstones of the Sadlerochit Formation were being

shed into the Alaskan North Slope Basin, possibly sourced from the same hinterland as the Bjorne.

Subsequent deposition in the Triassic saw the advance and retreat of deltaic systems into the basin, in response to the interplay of fluctuating sea levels and basin tectonics. The Roche Point and Pat Bay formations of the Schei Point group represent modest regressions into the basin. The subsequent transgressive phase of these cycles is typified by the deposition of bioclastic shelf limestones. These deltaic advances in the Middle to Late Triassic were the harbinger of the major advance across the basin of the deltaic systems that deposited the sandstones of the Heiberg Group (split distally by tongues of marine shale and sequence boundary unconformities into the Skybattle, Maclean Strait and King Christian formations). The source hinterland for the rivers that deposited the sandstones of the Heiberg Group was to the east of the basin. Over 1500 m of stacked delta-front, and delta-plain sediments were deposited in the basin depocentre, which acted as a sediment trap, allowing marine shale deposition to the northwest.

Marine transgression in the Early Jurassic drowned the Heiberg deltas, depositing thick shales of the Jameson Bay Formation and subsequently the Mackenzie King Formation in the Middle and Late Jurassic. From the Early Jurassic onwards, deposition was increasingly affected by source areas to the northwest. By the mid-Jurassic, the basin was confined between the emergent Sverdrup Rim to the northwest and Ellesmere-Bathurst-Melville islands to the southwest. Shoreface sandstones were deposited on either side of this Sverdrup seaway. Significant regressions during this period deposited sandstones of the Sandy Point, Hiccles Cove and Awingak formations. Quite complex interleaving of marine/deltaic sandstones and shales developed as the relative dominance of river systems shifted to and fro across the basin, restricting the connectivity of the seaway.

A major transgression at the beginning of the Cretaceous deposited shales of the Deer Bay Formation around the basin margins. There followed uplift and truncation associated with the onset of rifting in the Canada Basin in the Early Cretaceous. The subsequent regression deposited fluvio-deltaic sandstones (Isachsen Formation) across the basin and onto the newly formed continental margin.

From the Aptian onwards, deposition in the Sverdrup Basin became increasingly subsidiary to the building continental margin. A Major unconformity associated with regression and deposition of the Albian-

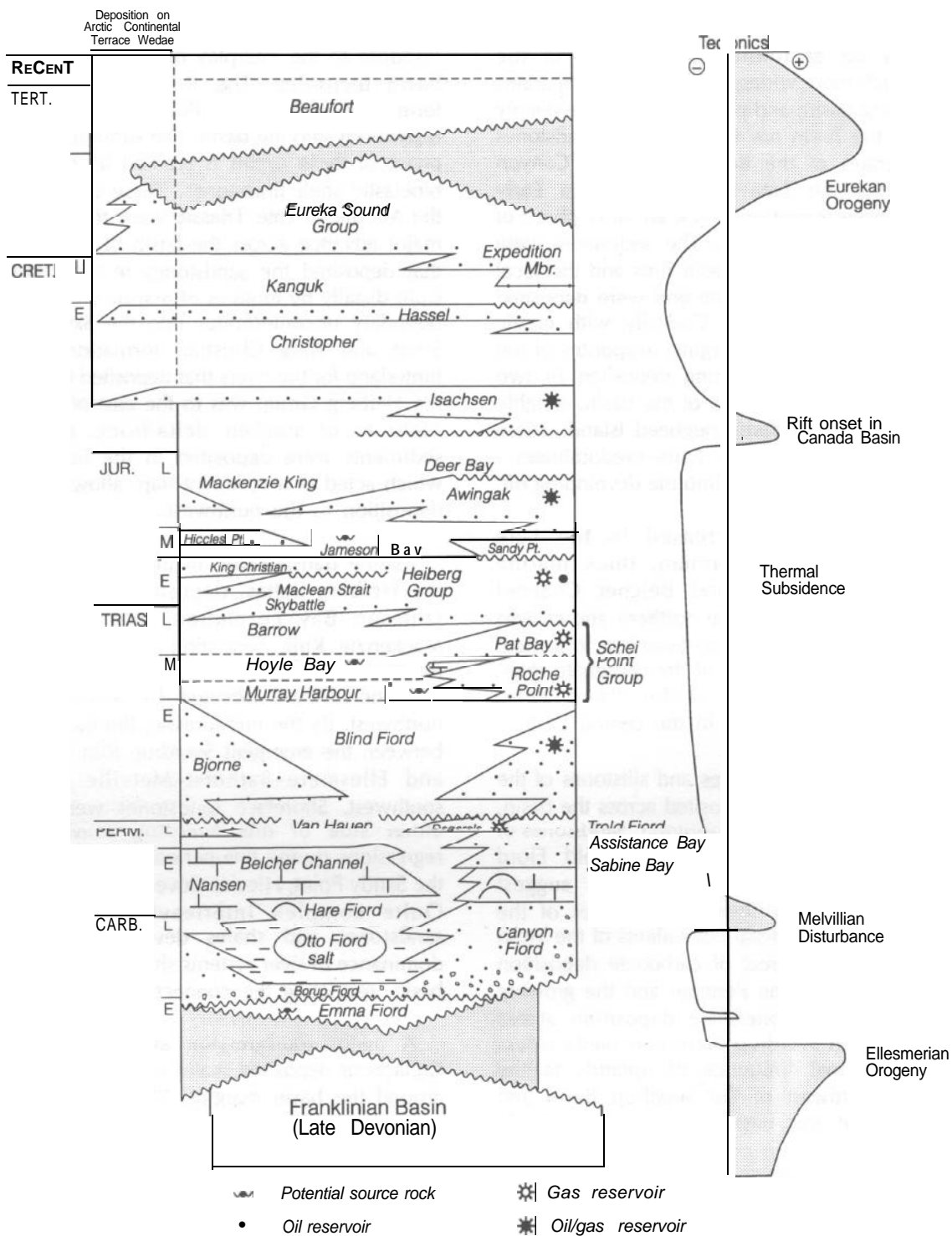


Figure 59. Summary stratigraphy of the Sverdrup Basin.

Cenomanian Hassel Formation correlates with break up in the Canada Basin. Deposition of thick Kanguk Formation shales in the Late Cretaceous reflects the flooding of continental margins worldwide during global highstand.

The basal member of the Eureka Sound Group (Expedition Member) represents the final pulse of continuous sedimentation in the Sverdrup Basin. The various units of the Eureka Sound Group range in age from Campanian or Maastrichtian to Late Eocene or earliest Oligocene. The group comprises alluvial, deltaic and estuarine members. The strata are rich in poorly consolidated, fine to very coarse grained sandstones, with abundant coal. The Eureka Sound Group is deeply truncated across the Sverdrup Basin by drainage systems developed during lowstands in the Paleogene and Holocene. Its marine/deltaic facies are more fully preserved on the Arctic Continental Terrace Wedge.

Reservoirs

The proven reservoirs of the Sverdrup Basin are shallow marine, delta-front and delta-plain sandstones of the Schei Point Group, Heiberg Group, Awingak and Isachsen formations. These have been the primary target for the bulk of exploratory drilling in the Arctic Islands and currently contain all the important discoveries.

- (1) Schei Point Group. In the Roche point gas field, 24 m of pay were encountered in marine sandstones of the Roche Point Formation and 15 m in the shallower Pat Bay Formation. Porosity in the better, lower pay zone is 18%. Reservoir quality was inferior in the lower zone.
- (2) Heiberg Group. Fourteen accumulations have been drilled in Heiberg Group sandstones, thirteen in the uppermost King Christian Formation. Average net pay in this formation is 30 m with maximum thicknesses of 60 m encountered in the Kristoffer discovery in stacked delta-plain sandstones. Porosity in Drake and Hecla is in the range of 18-20%. Reservoirs tend to be homogeneous and massive, with little variation in porosity about the mean. The sandstones are generally very clean and show excellent response on electric logs.
- (3) Awingak Formation. Gas was discovered at Whitefish in 10 m thick, coarsening-upward delta-front sandstones. Pay thicknesses of 5 to 8 m in each cycle combined for 17 m net pay, *averaging 16% porosity. Two hundred kilometres

to the east, at Cape Macmillan, gas was tested from a 22 m thick sandstone. The basal 7 m of this unit is coarsening-upward and of poor reservoir quality. This is capped by 15 m of clean delta-plain, proximal delta-front sandstones with 18% porosity.

- (4) Isachsen sandstones contain hydrocarbons in Balaena and Whitefish. Thirty metres of oil-bearing sandstone were encountered in Balaena in delta-front sandstones. Porosity in this youngest reservoir is 30%.

Although significant accumulations discovered to date have been in Middle Triassic and younger formations, Early Triassic Bjorne sandstones, and Permian Trolld Fiord sandstones and associated Degerbols carbonate also are potential reservoirs. Shows of both oil and gas were encountered in the Bjorne Formation in certain wells drilled in the Drake and Hecla fields, respectively. In Drake L-67, gas shows were noted deep in the well from the Degerbols. Although no shows have been noted in Permian carbonates, reefs along the Nansen/Belcher Channel shelf edge and isolated buildups encased by van Hauen shales are potential reservoirs.

The oldest potential reservoirs within the Sverdrup succession are continental sandstones of the Canyon Fiord and Borup Fiord formations. The conglomeratic facies of alluvial fans – characteristic of both formations, at least around the basin margins – tend to have poor porosity and permeability. Much more attractive from the viewpoint of potential reservoirs are aeolian sandstones, also typical of arid environments, and associated with Permian redbeds in many basins of the world. This facies has yet to be identified in the Sverdrup.

Structure, Traps and Seal

Three styles of structural traps are associated with existing discoveries in the Sverdrup Basin. These occur in geographically separate areas as shown in Figure 58.

- (1) A broad low-relief flexure parallels the southern margin of the Sverdrup Basin. This hosts two giant gas fields, Drake Point and Hecla, which fill local closures along the flexure to spill point. The fields are crossed by the northeasterly trending system of normal faults, which may have formed due to reactivation of the initiating rifts of the basin. The eastern offshore area of the Drake Point field is elongate along this northeasterly trend where the faults have larger throws and provide the dominant structural grain. The Drake Point gas field is the

largest field in Canada's frontiers, and typifies the large low dip structures found along the southern margin of the basin.

- (2) The second family of structures includes the Whitefish gas discovery and the Cisco oil and gas discovery west of Loughheed Island. Whitefish is typical of this class of structures: it is a dome, 25 km in diameter with relief of 175 m. Some extensional faulting is present but the frequency of faulting is low and throws are modest. Reservoir continuity across the fields appears good. These structures overlie the western Carboniferous salt subbasin and are formed over salt diapirs which, however, fail to pierce the stratigraphic level of the reservoirs. Two diapirs are exposed on northern Sabine Peninsula. The trend continues offshore in a northeasterly direction and parallels a second trend 30 km to the northwest. Trap fill in these structures is in excess of 50%.
- (3) The third class of structures lies offshore of southwestern Ellef Ringnes Island and King Christian Island – an area of some 10,000 km². These are anticlines of early Tertiary age developed or accentuated during the Eureka Orogeny. The structures have high relief and their development was facilitated by the eastern Carboniferous salt subbasin that underlies this area. Salt walls coring the anticlines are orthogonal to the east-west direction of principal stress developed during the orogeny. Discoveries in this type of structure are Kristoffer, Sculpin, Thor, Jackson Bay, Wallis, King Christian, Cape Allison, Cape MacMillan, Char and Balaena. The King Christian gas discovery is typical: the structure is elongate (12 by 5 km) with in excess of 1000 m of relief. These structures are poorly filled, to about 10% of their closure. This is likely the consequence of late growth, restricted hydrocarbon catchment area, declining hydrocarbon generation with overmaturity of source rocks, and, possibly, to surface seepage through extensive crestal faulting typical of these structures.

The discoveries at Skate and Maclean – offshore of eastern Loughheed Island – are intermediate between the domal structures west of Loughheed Island and the anticlinal folds and salt walls just described. They probably represent salt-related swells of pre-Eurekan age, reactivated and faulted by Eurekan compression.

Closure on tilted rift blocks contributes to the trap at East Drake. With this exception, the rift trend is undrilled. Similar fault-bounded traps are likely to be common along the Sverdrup Rim. Other structural

targets occur in the northeastern Sverdrup Basin, centred on the Fosheim Peninsula of Ellesmere Island. These lie within the Hazen Fold Belt where significant thicknesses of Mesozoic strata are preserved. Elsewhere on Ellesmere Island, uplift has removed much of the Mesozoic basin-fill.

Stratigraphic pinchout onto the southern flank of the basin appears to be a component of trapping in one of the gas pools in the Hecla field. This is likely to occur elsewhere along trend in many of the Mesozoic sandstones. Trapping also may occur down-dip from tar sands, for example, from those exposed at Marie Bay on western Melville Island. Depositional pinch-out onto the flanks of salt swells is also likely, as is trapping against salt intrusions.

Source Rocks

The oldest identified source rock in the Sverdrup Basin are the oil shales of the Carboniferous Emma Fiord Formation. Total organic carbon content, measured on outcrop samples, ranges up to 50%. The shales are rich in alginite and are thought to have been deposited in a lacustrine environment. The Emma Fiord Formation is likely to be overmature (but possibly a rich source of gas) except at the extreme margins of the basin. Dark, organic-rich shales also have been noted in the Upper Carboniferous and Permian Hare Fiord and van Hauen formations.

The thickest and most widely distributed of the source rocks in the Sverdrup Basin are the distal marine facies of the Triassic Schei Point Group' (Murray Harbour and Hoyle Bay formations). Recurrent deposition of organic rich shales within the basin was favoured by low-energy stratified waters in areas remote from deltaic influx. Switching of sediment source direction ensured that these source rocks were widely distributed within the basin, albeit at slightly different times throughout the Triassic. Analysis of samples from Schei Point shales shows much variation about an average TOC of 4%. All samples contain marine Type II organic matter of algal origin with excellent potential as an oil source.

Extracts from Schei Point shales show close geochemical correlation with all discovered oils within the basin, suggesting a common source for oil. Indeed, the distribution of existing discoveries is well explained by the regional maturity map for the Schei Point shales alone. The presence of gas is explained by the flanking position of gas accumulations to areas of overmature Schei Point source rock, raised to maturity levels beyond the oil window by high heat flow associated

with salt or volcanic intrusion and/or depth of burial. Mixed gas and oil discoveries can be explained by invoking more than one phase of hydrocarbon migration linked to successive tectonic events that affected the maturity of the source rock. As a general observation, Triassic source rocks become overmature east of a line running roughly down the axis of Ellef Ringnes Island and southeast to Ellesmere Island.

Jurassic shales of the Jameson Bay Formation also contain Type II kerogen and are oil-prone west of Loughheed Island, but this interval is only marginally mature. Maturity levels may increase locally near salt intrusions. Farther east, where Type III organic matter predominates in more proximal deltaic facies, this and most other Mesozoic shales can be expected to be more gas-prone.

Potential

The Sverdrup Basin is a large and diverse petroliferous basin with an excellent discovery record. Proven plays in the Triassic sandstones contain accumulations of giant class and many smaller discoveries can be expected. No tail off in the cumulative discovery record is evident. Larger accumulations tend to be in the structures of subtler relief removed from the influence of the Eurekan Orogeny. Stratigraphic traps in these reservoirs are entirely unexplored and the potential for large closures is high, especially along the southern margin of the basin. Up-dip from the western salt subbasin (in and around Sabine Peninsula) the structures are likely to contain gas. Farther west, the Schei Point shales are likely to be less mature, and oil accumulations in similar traps are possible. One example of such a potential field are the tar sands at Marie Bay on western Melville Island, which are hosted in Lower Triassic Bjerne sandstones. The distribution of the Bjerne Formation in the southwestern basin makes this an interesting target below the Heiberg and Schei Point groups. The Awingak Formation is of interest throughout the western Sverdrup, particularly in view of its association with coeval source rocks west of Loughheed Island.

Numerous undrilled fault-bounded structures are likely to exist offshore in addition to structural/stratigraphic traps associated with salt deformation. Horst blocks are particularly attractive and are likely to be within drilling depth around the basin margins.

Generally speaking, the risk of source rock overmaturity, break down of trap integrity and biodegradation of oils increases towards the eastern margin of the basin: large economic prospects are less

likely in these areas. Although the discovery rates have been high, these considerations weigh against pursuit of prospects in the zone of Eurekan structures.

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FRANKLINIAN BASIN

Age	Cambrian to Early Carboniferous
Area	Arctic Platform 780,000 km ² (47% onshore) Arctic Fold Belt 240,000 km ² (62% onshore) and extending at depth beneath the Sverdrup Basin
Depth to Target Zones	0.5 to 5 km
Maximum Basin Thickness	10 km
Hydrocarbon Shows	Oil staining in Thumb Mountain (Upper Ordovician), Bird Fiord and Weatherall formations (Middle Devonian). Gas shows in first well drilled in basin – at Winter Harbour No. 1 A-09 in the Upper Devonian clastic wedge
Sole Discoveries	Bent Horn N-72 (1974: 43° API oil)
Discovered Resources	Oil: 1.0 x 10 ⁶ m ³
Production	Oil: Bent Horn: 321,470 m ³ to the end of 1993
Basin Type	Carbonate-dominated continental margin (miogeocline) in lower Paleozoic. Foreland Basin in Late Devonian
Depositional Setting	Marine carbonate/shale basin; switching to siliciclastic marine/deltaic/fluvial in Late Devonian
Reservoirs	Early to Middle Devonian reefs; carbonate bank margins and shallow-water shelf carbonates and mounds; sandstones of the clastic wedge
Regional Structure	Highly structured Arctic Fold Belt outboard of the Arctic Platform
Seals	Marine shales (Cape de Bray Formation at Bent Horn)
Source Rocks	Ordovician and Lower Devonian shales (gas); shales of the clastic wedge (oil?); Middle Devonian carbonates and shales coeval with reefs (oil?); structurally juxtaposed source rocks of the overlying Carboniferous and Mesozoic (oil?)
Depth to Oil Window	At surface in the Arctic Fold Belt
Total Number of Wells	50

Geological Setting (Fig. 60)

The Early Cambrian to mid-Devonian Franklinian Basin was contiguous with the Hudson Platform to the southeast and the Interior Platform to the southwest, and part of an uninterrupted continental margin bordering the North American craton. Carbonate deposition predominated over this lengthy period, constructing a thick pericratonic wedge (miogeocline). Beginning in the Middle Devonian, siliciclastic sediments derived from eastern highlands thrown up by the Ellesmerian Orogeny spread across the region. The deposition of these thick foreland basin deposits – the ‘clastic wedge’ of Embry and Klovan (1976) – heralded the folding and uplift of much of the Franklinian Basin at the culmination of the Ellesmerian Orogeny.

The southern edge of the Arctic Fold Belt marks the limit of folding of Franklinian strata by Ellesmerian compression. The Arctic Fold Belt is the southern component of a broad region of past tectonic activity – the Innuitian Tectonic Province – which also includes distal parts of the Franklinian Basin, the Sverdrup Basin and the Arctic Continental Terrace Wedge.

South of the Arctic Fold Belt, the Arctic Platform is generally mildly deformed, except in the vicinity of the Boothia Arch. The axis of this major uplift of Silurian vintage strikes north from the Canadian Shield, exposing Archean rocks along its length. The structural influence of the arch extends north of Barrow Strait into Cornwallis Island and the Grinnell Peninsula of Devon Island, where complex interference structures developed at its intersection with the Arctic Fold Belt.

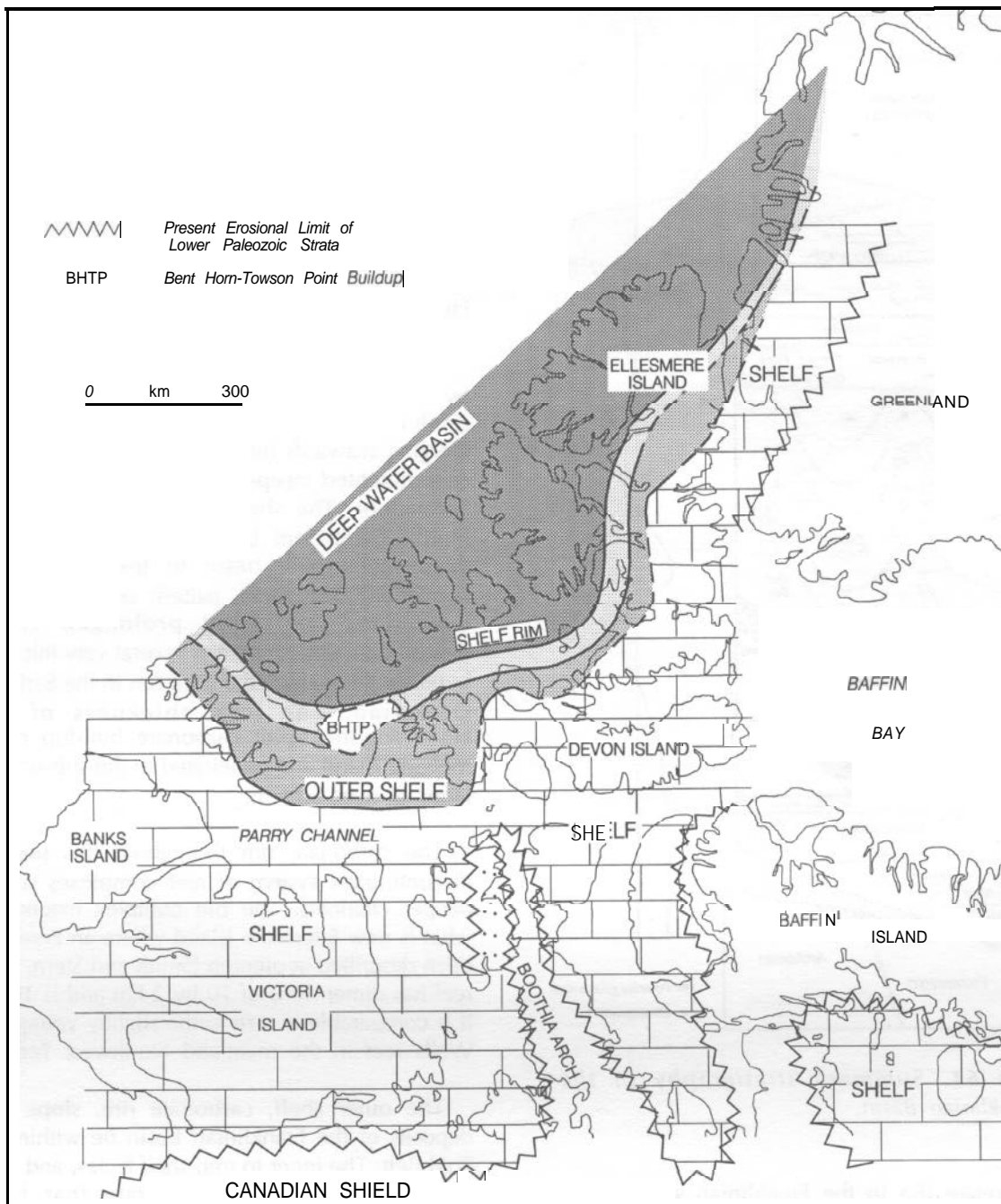


Figure 60. Generalized Cambrian to Middle Devonian paleogeography, Franklinian Basin.

Stratigraphy (Fig. 61)

The thickness of the Cambrian increases from the edge of the Canadian Shield to over six kilometres in northeastern Ellesmere Island. Within the Arctic Platform, sandstones of the Gallery and Turner Cliffs formations were widely deposited following a long period of peneplanation, which separates Cambrian

rocks from the Precambrian. The succession on Ellesmere Island is much thicker and predominantly marine. It includes shelf carbonates (Ella Bay Formation), deltaic sandstones (Rawlings Bay Formation) and distal equivalent (Archer Fiord Formation), and shelf mudrocks of the Kane Basin Formation. Deep-water equivalents (Grantland Formation) are found in northeastern Ellesmere Island.

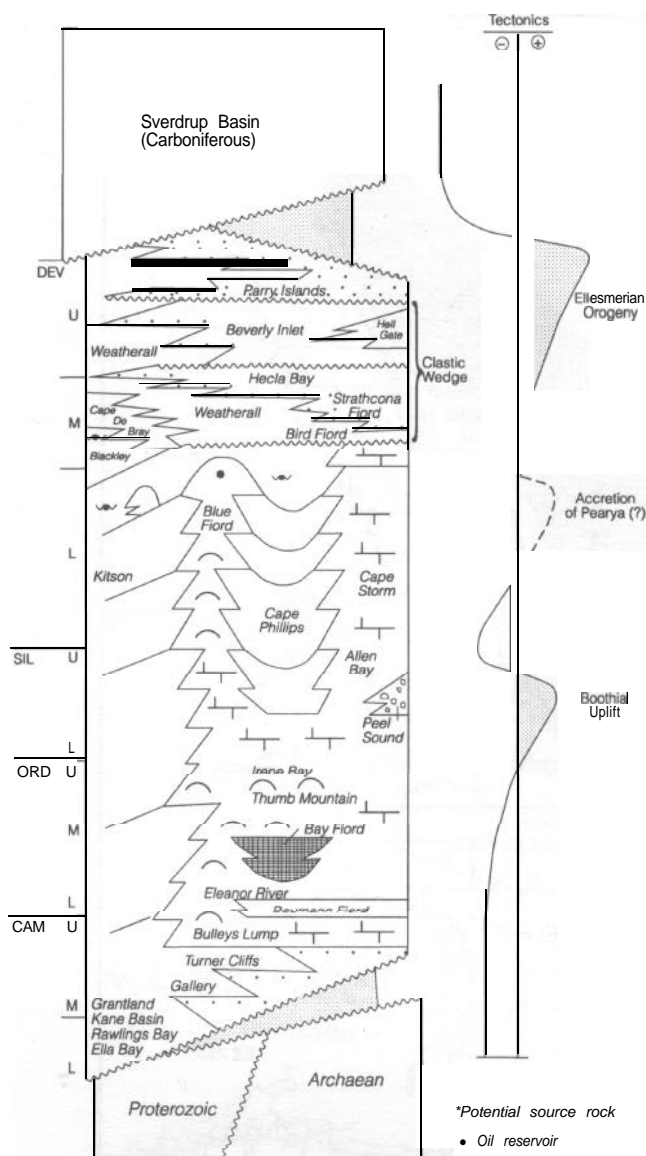


Figure 61. Summary stratigraphy of the Franklinian Basin.

A carbonate rim to the Franklinian shelf began to develop in the Early Ordovician (Bulleys Lump Formation), restricting marine circulation across the inner shelf. Laminated carbonates, anhydrite and gypsum of the early Middle Ordovician Baumann Fiord Formation were deposited, succeeded by marine limestones of the Eleanor River Formation. An evaporitic basin was re-established after deposition of the Eleanor River Formation. Thick halite of the Bay Fiord Formation occurs in the subsurface of Bathurst and Melville islands within a more extensive area of gypsum-anhydrite deposition.

Marine environments were established across most of the continental margin late in the Ordovician and

persisted into the Late Devonian. This lengthy period saw rapid accretion of the carbonate-dominated continental margin. Ordovician units include marine limestones of the Thumb Mountain Formation (up to 400 m thick, overlying Bay Fiord evaporites across much of the Arctic Platform), Irene Bay and Allen Bay formations. Reef builders were active in the Middle and Late Ordovician in northeastern Melville Island where mounds up to 30 m high and 1500 m in diameter have been described. Similar mounds are known from the Hudson Platform.

Silurian to Devonian deposition was characterized by division into a shallow water carbonate shelf to the south and east (Allen Bay and Cape Storm formations), merging seawards into deeper shelf environments with re-sedimented deep-water carbonates (Cape Phillips Formation). The shelf was rimmed by reefs ("Blue Fiord" Formation) bordering a plunging slope and deep-water shale basin to the northwest (Kitson Formation). This facies pattern endured until the Late Devonian, conferring prolonged stability in depositional environments. Several very thick carbonate buildups grew along the shelf rim in the Early to Middle Devonian. The total thickness of the Bent Horn-Towson Point carbonate buildup exposed on Melville Island and penetrated in the subsurface at Bent Horn is over 600 m.

The carbonate rim throughout this period was a discontinuous system of reef complexes separated by deeper channels. The rim complex extended east to what is now Ellesmere Island where an Emsian reef has been described at outcrop (Smith and Stern, 1987). This reef has dimensions of 10 by 2 km and is 100 m thick. It is comparable in size to the slightly younger Norman Wells reef in the mainland Northwest Territories.

The outer shelf, carbonate rim, slope and basin deposits of the Franklinian Basin lie within the Arctic Fold Belt. The inner to mid shelf facies, and most of the Cambrian to Ordovician strata that have been penetrated lie within the Arctic Platform. Local complexity and an interruption in carbonate sedimentation is present in the vicinity of the Boothia Arch where conglomerates of the Peel Sound Formation were shed from the arch during its main phase of growth in the Silurian.

The Ellesmerian Orogeny saw the influx of siliciclastic sediments from east to west across the carbonate shelf starting in the earliest Middle Devonian. The Ellesmerian Orogeny may be linked to plate movements that also emplaced an exotic terrane, Pearya, on the northern edge of the region. Pearya may have been a supplementary source of quartzose

sediments. These deposits form a massive wedge (maximum preserved thickness of 4 km), which originally thickened to the west (and distally) towards the modern coasts of the Beaufort Sea. Deposition of the clastic wedge ended as Ellesmerian uplift propagated westwards, resulting in the erosion of major thicknesses of the clastic wedge and their redeposition beyond the confines of the Arctic Islands.

The earliest strata assigned to the clastic wedge are fine grained clastics of the Blackley Formation, which overlie black shales of the Kitson Formation. Blackley strata were deposited at the toe of an advancing slope on which siltstones and shales of the Cape de Bray Formation were deposited. Diachronous upwards-coarsening characterizes the westward regression of the coarse-grained clastic depositional systems and the Cape de Bray is overlain and laterally equivalent to deltaic and marine shelf deposits of the Bird Fiord and Weatherall formations. The first incursion of fluvial deposits into the basin is recorded by sandstones of the Strathcona Fiord Formation on Ellesmere Island, followed by the much more widespread braided-stream deposits of the Hecla Bay Formation in the late Middle Devonian. An unconformity above the Hecla Bay Formation marks the end of the first of three main regressive pulses within the clastic wedge. The second advance of the deltaic systems into the basin in the Late Devonian deposited the Beverley Inlet Formation across most of the basin (the Fram, Hell Gate and Nordstrand Point formations are proximal equivalents on Ellesmere Island). The final pulse deposited the Parry Islands Formation, which again spread fluvial and coastal plain facies across the basin. There is a gap in the stratigraphic record above the Parry Islands Formation, extending from the latest Devonian to earliest Carboniferous. This hiatus marks the end of deposition within the Franklinian Basin.

Reservoirs

Bent Horn Field

The Bent Horn oil pool was discovered by the drilling of the Bent Horn N-72 well, spudded in 1973. The reservoir is in reefal limestones of the Blue Fiord Formation. The field produces 45° API oil from a single well (A-02). The discovery lies within the highly structured transition zone between the Arctic Fold Belt and the Sverdrup Basin, in the upper of two northward-directed backthrusts, truncated and sealed on the southern side by a normal fault of 300 m throw. The pool is confined on the eastern side by a facies transition from reefal carbonate to shale.

The Bent Horn pool has been delineated by six wells (including the discovery well). Two wells recovered oil, one is rated as an oil show and three were dry holes. Only the A-02 well penetrated an oil zone in the overthrust sheet, and has proved to be the only well able to sustain production. This well is capable of 5300 bbls/day with minimal water production. The F-72 and N-72 wells missed the nose of the upper thrust sheet but encountered oil in the footwall of the thrust. The extent of the N-72 pool appears limited on the basis of production tests. Subsequent sidetracking of the F-72 well to intersect the upper thrust sheet failed to encounter any porous zones.

Drilling has demonstrated that the Blue Fiord limestones are generally tight with local porosity in vugs and caverns. Permeability is improved by fracturing, but this appears to be highly localized. The field has an active water drive. The field is limited to the upper thrust sheet and its extent along strike is uncertain. On production since 1985, the well has produced **321, 469** m³ of oil to the end 1993. The porosity type and the complex structural setting makes reserve determination difficult and the estimate of 1.0×10^6 m³ is subject to considerable uncertainty.

Other Potential Reservoirs

Basal Cambrian sandstones are poorly consolidated and usually have good porosity in outcrop. These sandstones are diachronous, and older equivalents may be present at depth in the more distal parts of the Franklinian Basin. Although good porosity has been noted at outcrop, porosity in the subsurface is unlikely to be better than fair. Cambrian reservoirs in the Colville Hills of mainland Northwest Territories average 12% porosity.

Upper Cambrian and Ordovician precursors of the carbonate rim reefs of the Blue Fiord Formation have modest potential as reservoirs. Porosity development in these carbonates and the much more extensive mounds and patch reefs and shallow-water carbonates of the shallow Franklinian Shelf are potentially porous, but porosity development is probably rare.

Sandstones of the clastic wedge are potential reservoirs with reservoir quality depending on depositional facies. Porosity seldom exceeds 10% in the deltaic/marine sandstones of the Bird Fiord and Weatherall formations on Melville Island, but more proximal fluvio-deltaic sandstones may exhibit superior reservoir characteristics.

Structure, Traps and Seals

Large regular folds are evident at outcrop in the Parry Islands section of the Arctic Fold belt. Seismic and field studies reveal more complex structure at depth, of which this is the surface expression in younger horizons. Multiple detachments and ramping of thrust sheets are present within the Ordovician salt and weaker shale intervals in the predominantly carbonate sequence. These show a progression in structural complexity that can seldom be deduced from outcrop studies alone, and which greatly increases the permutations of potential reservoir, seal and source to be found within the fold belt. Drilling on structural targets within the Franklinian sequence has not been based on modern interpretations of the target structures. Recent recognition of the effects of the Melvillian Disturbance in the Canrobert Fold Belt on northwestern Melville Island – distinct in age and style of deformation from the Parry Islands Fold Belt – underlines the recent advances in our understanding of the structural complexity of this region (see Harrison, 1991).

The larger amplitude structures of the Arctic Fold Belt are found within the shelf carbonate areas of the Franklinian Basin. Basinward (i.e., to the north) the structuring of the predominantly shale succession has resulted in chevron folding of much greater frequency.

Structural traps within the fold belt include simple anticlines, thrust anticlines, sub-thrusted sheets and sub-salt traps, and basement fault blocks. Shale horizons and salt provide seals. West of 105°W, there has been little tectonic influence since the end of the Ellesmerian Orogeny, and the risk of seal failure as a result of late reactivation of the structures is slight. This is not the case close to the margin of the Sverdrup Basin, where active extensional tectonics and possibly strike-slip movement along the many thrust sheets risked the integrity of pre-existing traps.

Anticlinal structures, so evident in the Arctic Fold Belt, are absent from the Arctic Platform. Potential traps are related to faulting of the basement and especially to faulting associated with arches. Archean rocks are exposed along the crest of the Boothia Arch. This major structure is thought to be a westward-verging thrust and most of the associated surface structures have been mapped along its western flank. The Cambrian to late Silurian succession on both flanks probably does not exceed 2000 m in total thickness. The three wells drilled on Prince of Wales and Somerset islands tested structures on the flanks of the Boothia Arch.

Stratigraphic traps include reef development on the rim of the carbonate shelf. This depositional transition from shelf to slope resulted in a transition in gross geotechnical properties, and hence of focus for structural discontinuity. In this sense it is hardly surprising that discoveries along the trend of the main barrier may have the added structural complexity of faulting. Large reefs also develop on the slope seaward of the main reef trend. Reefs of this type are more likely to be encased in shale and are removed from the main zone of structural discontinuity at the shelf edge. Patch reefs and oolitic shoals within the shallow waters of the shelf are likely to be common in Ordovician through Middle Devonian strata of the Arctic Platform.

Source Rocks

Although uncommon within the thick carbonate succession of the lower Paleozoic, some potential source rocks have been identified. Black shales of the Upper Ordovician Cape Phillips Formation and Lower Devonian Kitson Formation have 3 to 5 % TOC and high gas yields. The source of the oil at Bent Horn is unknown but circumstantial evidence suggests that it is derived from encasing shales of the Cape Phillips Formation.

Within the Middle to Upper Devonian clastic wedge, shales of the Weatherall, Bird Fiord, Blackley and Cape de Bray formations are potential oil sources. Maturity levels within these horizons increase to the point of overmaturity towards the west, the result of deep burial beneath sediments of the clastic wedge, subsequently eroded. Potential for gas generation also exists within the clastic wedge.

Potential

Three petroleum systems may exist in the Franklinian Basin: all are under-explored and incorporate many distinct plays. Potential ranges from fair (Cambrian to Silurian), to good (Lower to Middle Devonian carbonates and Middle to Upper Devonian clastics). Only one play can be considered proven – the Bent Horn discovery: the remainder are conceptual, although supported by hydrocarbon shows and promising geology.

Petroleum System 1. Basal Cambrian to Lower Ordovician (sandstone and carbonate reservoir facies and associated source rock facies).

Lower Ordovician carbonates in structures beneath the Bay Fiord salt are a potential gas play due to the high level of maturity of any communicating source rock. Top seal in the form of halites of the Bay Fiord Formation is confined to Melville and Bathurst islands. Lack of porosity and absence or over-maturity of source rock are the chief risks of these plays, although prospects for sealing and preservation of accumulations beneath the salt are favourable.

Cambrian sandstones form an important reservoir rock on the Interior Platform in the Colville Hills and are likely to exhibit similar reservoir character across the Arctic Platform. However, the absence of any extensive salt-basin of Cambrian age on the Arctic Platform reduces the likelihood of effective top seals for Cambrian sandstones. Traps are most likely to be stratigraphic onlap and pinchout onto the basal Cambrian unconformity. Such traps are well positioned to intercept hydrocarbons migrating up-dip from deeper parts of the basin.

Petroleum System 2. Upper Ordovician to Middle Devonian (carbonate buildups and associated source rock facies).

Upper Ordovician carbonates (e.g., Thumb Mountain Formation) in Ellesmerian anticlines and thrust plates are tight or yielded water, but the presence of porosity, oil staining, and gas shows, combined with the close proximity to source rocks, indicate that undrilled closures still have some potential, probably for gas.

The Silurian to Middle Devonian shelf rim and isolated carbonate buildups on the upper slope have the best potential for hydrocarbon discoveries in lower Paleozoic strata. Reefal buildups appear to be relatively frequent within this trend. Porosity is present, although locally plugged with bitumen. The Bent Horn pool lends confidence that active oil source rocks occur in coeval off-reef facies. There is potential for major oil fields within this play.

Petroleum System 3. Upper Devonian clastic wedge (sandstones and associated source rocks).

Gas shows in the Winter Harbour well, and oil staining in surface and some subsurface samples are recorded from Upper Devonian sandstones of the clastic wedge. Potential reservoir rocks are in close stratigraphic

proximity to source rocks both within the clastic wedge and to source rocks near the base of the overlying Sverdrup succession. Maturation levels are generally favourable. Structural targets include anticlines, and fault-bounded thrust sheets within the Arctic Fold Belt and along the margin of the Sverdrup Basin.

Future exploration is likely to focus on oil prospects in reef complexes along the carbonate rim, particularly close to the structural interface of the Arctic Fold Belt and the Sverdrup Basin. The major structures of the Arctic Fold Belt involve clastic wedge sandstones, which form a major play for both gas and oil. Potential for both plays to host major pools of oil and gas is good.

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ARCTIC CONTINENTAL TERRACE WEDGE

Age	Cretaceous to Recent
Depth to Target Zones	?
Maximum Basin Thickness	12 km
Hydrocarbon Shows	?
Discovered Resources	None
Basin Type	Passive margin
Depositional Setting	Transitional to marine shelf and oceanic basin
Reservoirs	Fluvio-deltaic/marine sandstones, turbidites(?)
Regional Structure	Extensional faulting; rotated fault blocks
Seals	Marine shales (?)
Source Rocks	Unknown
Depth to Oil Window	>3000 m (?)
Total Number of Wells	10 wells have tested the proximal edge from onshore locations along the Sverdrup rim

The Arctic Continental Terrace Wedge is known to contain thick accumulations of sediments. Seismic refraction studies on the Arctic continental shelf north of Axel Heiberg Island reveal the presence of a thick (10 km) deformed sedimentary succession on the outer shelf. Seismic reflection profiles obtained along the path of the Ice Island show the presence of a wedge of faulted sedimentary strata (2 km) on the inner shelf, west of Axel Heiberg Island.

The wedge comprises Upper Cretaceous and Paleogene sequences that correlate with oil and gas bearing sequences in the southern Beaufort Sea and Mackenzie Delta. The Eureka Sound Formation, while

predominantly fluvial at outcrop in the Arctic Islands, is likely to have deltaic and marine equivalents offshore, which may include potential reservoir and source rocks. These may have been sufficiently buried to reach maturity beneath a thick wedge of poorly consolidated Beaufort Formation sandstones deposited above the circum-Beaufort unconformity in the Early Miocene.

However, the geographic remoteness, and the large proportion of the basin that lies beneath the shifting Arctic Ocean ice pack removes the region from possible economic exploitation in the foreseeable future.

CHAPTER 6 – EASTERN ARCTIC

LANCASTER SOUND BASIN

Age	Early Cretaceous(?)–Tertiary over Proterozoic to Paleozoic basement
Maximum Basin Thickness	8 km
Discoveries	None
Basin Type	Mesozoic rift basin overlying Proterozoic to Paleozoic basin floor
Depositional Setting	Fluvio-deltaic to marine
Reservoirs	?Cretaceous and Paleogene sandstones, ?Palaeozoic sandstones and carbonates, ?Proterozoic sandstones
Regional Structure	Block faulting, half-grabens
Seals	?Marine shales
Source Rocks	?Lower Cretaceous (gas prone) ?Upper Cretaceous, Paleocene marine shales (oil potential)
Depth to Oil Window	Unknown
Seismic Coverage	In excess of 60 000 km of marine seismic form an adequate seismic grid
Area	13,250 km ²
Area under Licence	931,640 ha (Exploration Licence held under moratorium)

(Water depths reach 800 m, and are generally in excess of 100 m, except within a narrow coastal zone. Ice cover extends from October to late June. Icebergs are common.)

This undrilled basin is a Mesozoic and Cenozoic rift basin comparable in size to the Viking Graben in the North Sea. It contains numerous block faulted structures identified on the basis of an extensive seismic grid. The basin stratigraphy is expected to include Cretaceous and Tertiary reservoir rocks, and mature source rocks for both gas and oil.

Geological Setting (Figs. 62-64)

Lancaster Sound Basin connects the partially drowned interior of the North American craton – the Canadian Arctic Islands – with Baffin Bay and the North Atlantic. The basin originated as a rift at the northwestern end of Baffin Bay. Unlike Baffin Bay, the continental crust in Lancaster Sound has not been significantly thinned and no sea-floor spreading has taken place. The fill of the basin consists of Mesozoic, Tertiary and Quaternary sediments and is bordered to the north and south by Proterozoic and lower Paleozoic rocks exposed on Devon Island to the north and on Bylot Island and the Borden Peninsula of Baffin Island to the south. In cross-section, the basin is a half-graben with the basin

axis adjacent to the Devon Fault. The displacement of several thousand metres on this fault throws Proterozoic rocks exposed on Devon island against Mesozoic to Tertiary basin-fill. The basin shallows to the west into Barrow Strait and also to the east across the Sherrard Ridge, which acts as a sill separating Lancaster Sound and Baffin Bay basins.

Exploration History

Exploration for oil and gas has been limited to seismic operations and geological field work along the margins of the basin. Although drilling in Lancaster Sound was approved in principle in 1974, no well was drilled. A

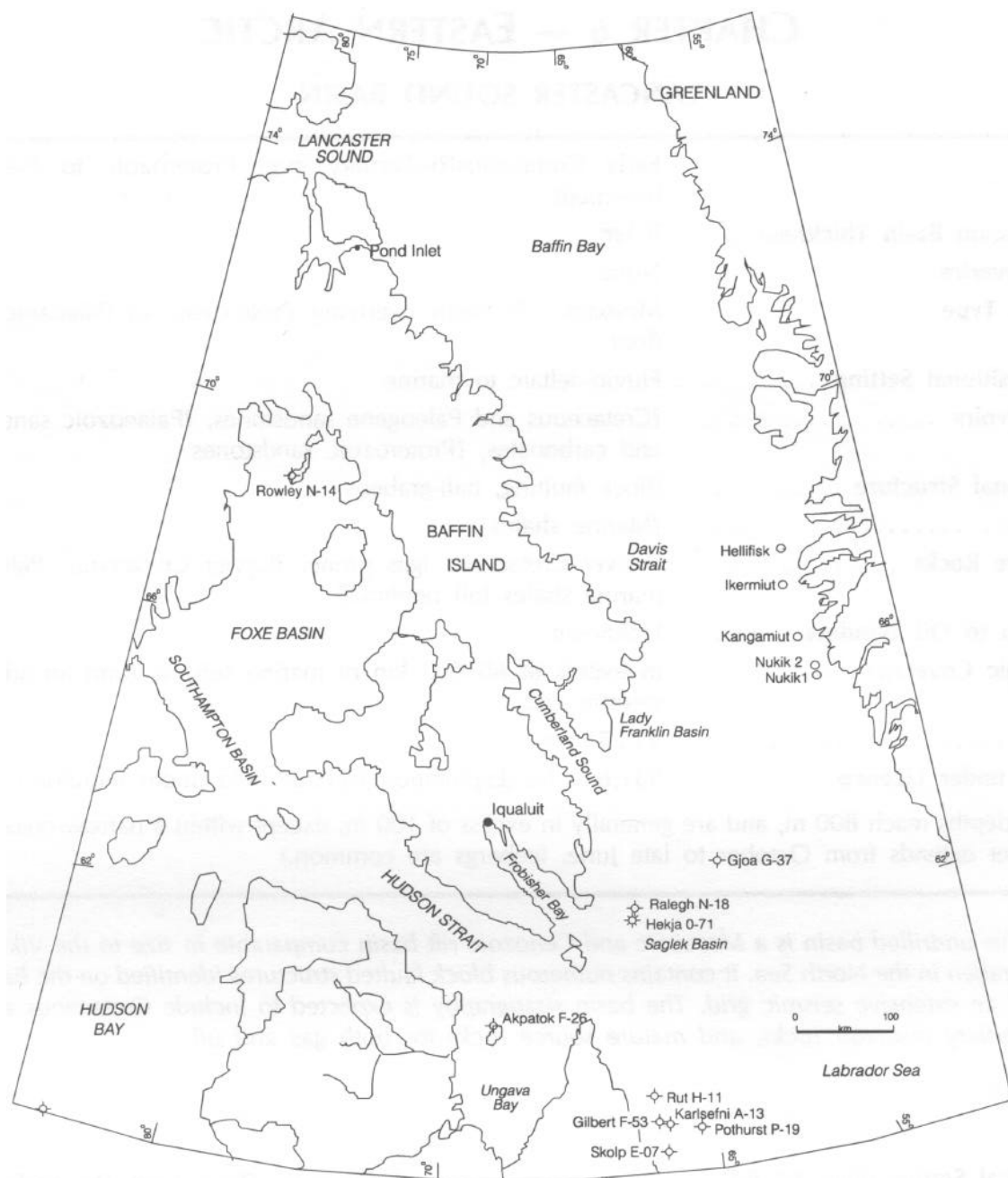


Figure 62. Geography and well locations, eastern Arctic.

moratorium on drilling was put in place following an environmental review in 1978. However, the Lancaster Sound Regional Land Use Plan considered that hydrocarbon exploration was not necessarily an incompatible land use.

Exploration rights held in the area are not subject to work programs while the moratorium is still in effect.

Stratigraphy (Fig. 65)

Archean rocks exposed along the length of Baffin Island, eastern Devon Island and eastern Ellesmere Island form an uplifted margin to Baffin Bay from which the Proterozoic and Lower Paleozoic cover has been largely stripped. The Cambrian to Middle Silurian succession has been described from the southwestern

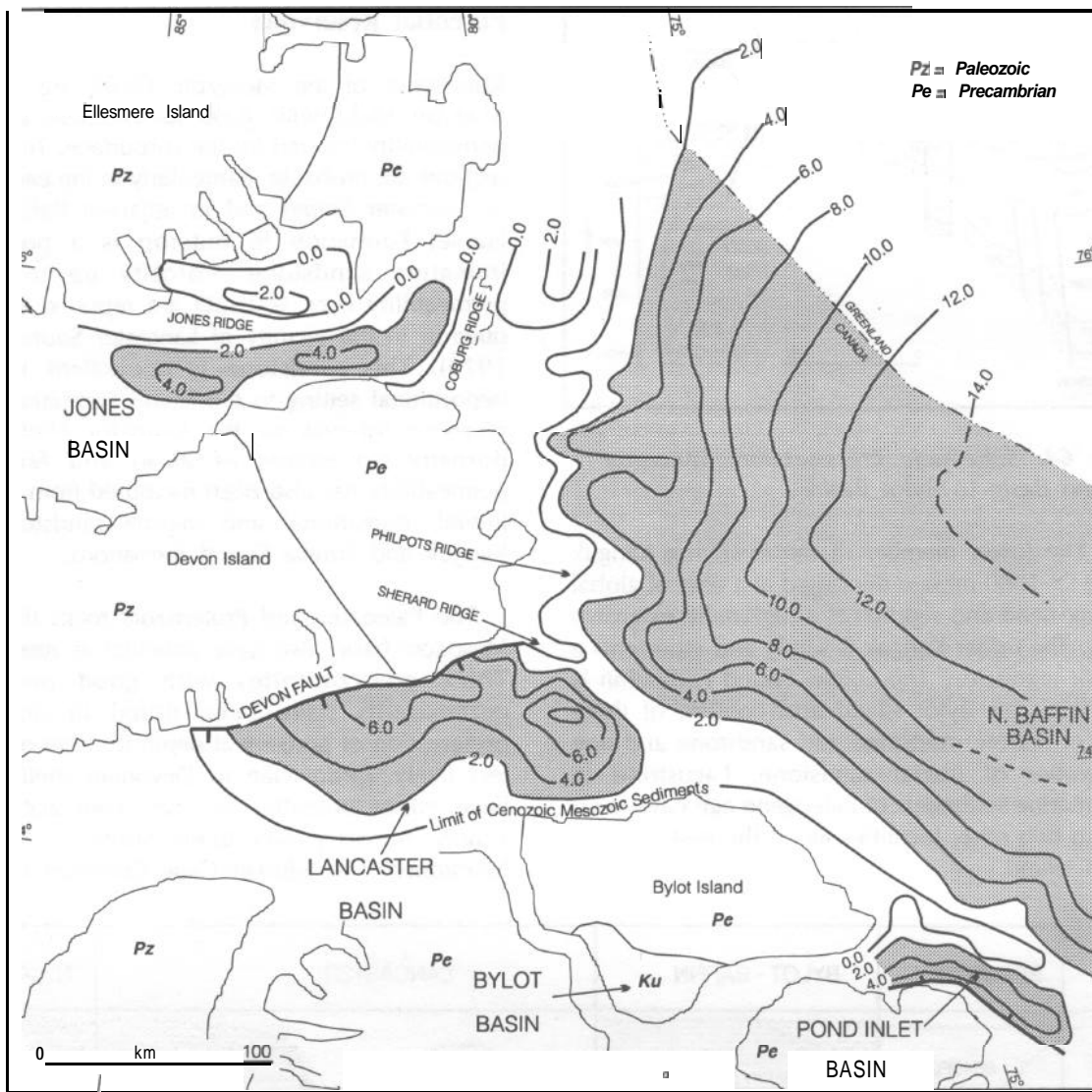


Figure 63. *Isopach (thousands of metres) of Mesozoic-Cenozoic strata, Lancaster Sound and adjacent areas.*

margin of the Lancaster Sound Basin (Jackson and Sangster, 1987). This consists of predominantly clastic Cambrian strata (Gallery and Turner Cliffs formations) superseded by limestones and dolostones of the Lower Ordovician (Ship Point Formation). Devonian formations (the Allen Bay and Blue Fiord) may be preserved in the western end of the basin. From these observations, it is probable that the Mesozoic basins in Lancaster Sound, Jones Sound and Eclipse Trough are floored by Proterozoic rocks in the east, with lower Paleozoic rocks preserved farther west beneath a major sub-Cretaceous unconformity.

Cretaceous to Tertiary sediments outcrop on Bylot Island and adjacent to Pond Inlet on northeastern Baffin Island. The fill of the Lancaster Sound Basin has been

inferred from the outcrop stratigraphy on Bylot Island (McWhae, 1979) and the seismo-stratigraphy of the basin sequences by Harper and Woodcock (1980). The oldest Mesozoic sediments in Lancaster Sound are probably Albian or possibly older in the deepest parts of the rift. Strata of the Hassel Formation (Albian-Cenomanian), the Kanguk Formation (Campanian-Maastrichtian), and the Eureka Sound Formation (Paleocene-Eocene) have nomenclature common to the Sverdrup Basin of the Arctic Islands and are likely to be represented as thickened successions in the offshore.

The Hassel Formation is predominantly fluvial. Thick, coarse grained sandstones with thin coals are equivalent to the sandstones of the Bjarni Formation

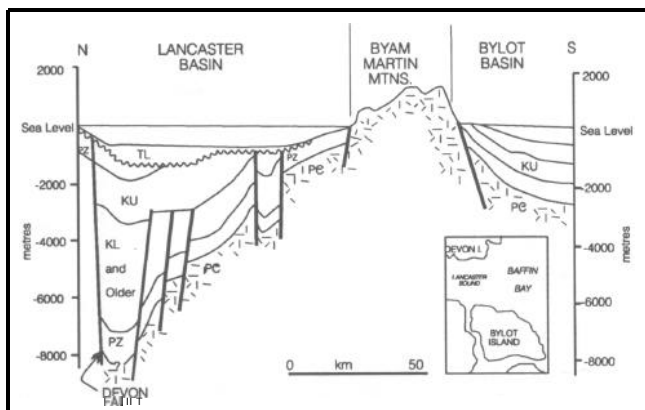


Figure 64. Schematic cross-section, Lancaster Sound Basin to Bylot Basin.

offshore. The lower member of the overlying Kanguk Formation (> 1000 m) was deposited at a time of global marine highstand and represents a regionally extensive shale unit. The upper Kanguk is sandy and represents a subsequent regression. The Eureka Sound Formation is 1600 m thick on Bylot Island and consists of three members of marine mudstone and sandstone and one thick member of fluvial sandstone. Lacustrine to marginal marine sediments of Paleogene age have been noted from two other localities along the east coast of the Baffin island.

Potential Reservoirs

Sandstones of the Mesozoic rift-fill are all potential reservoir rocks with good to excellent porosity and permeability inferred for the subsurface. Thick reservoir sections are probable, particularly in the eastern portion of Lancaster Sound and in adjacent Baffin Bay. The Hassel Formation in outcrop is a poorly sorted immature sandstone. Porosity up to 28% and permeability over 400 mD are reported from surface outcrop in the vicinity of Lancaster Sound (McWhae, 1979). This sandstone is equivalent in age and depositional setting to the Bjarni Formation, a proven reservoir interval on the Labrador Shelf. Excellent porosity (in excess of 20%) and fair to good permeability has also been measured from interbedded fluvial, transitional and marine sandstones of the Kanguk and Eureka Sound formations.

The Paleozoic and Proterozoic rocks that floor the Mesozoic basin also have potential as reservoir rocks. Thick quartzarenites with good porosity and permeability have been noted in outcrop, but preservation of porosity at depth in these older units is less likely. Ordovician to Devonian shelf carbonates have minor potential for significant accumulations. Vuggy porosity has been noted in Ordovician limestones. The Silurian Cape Crawford Formation is

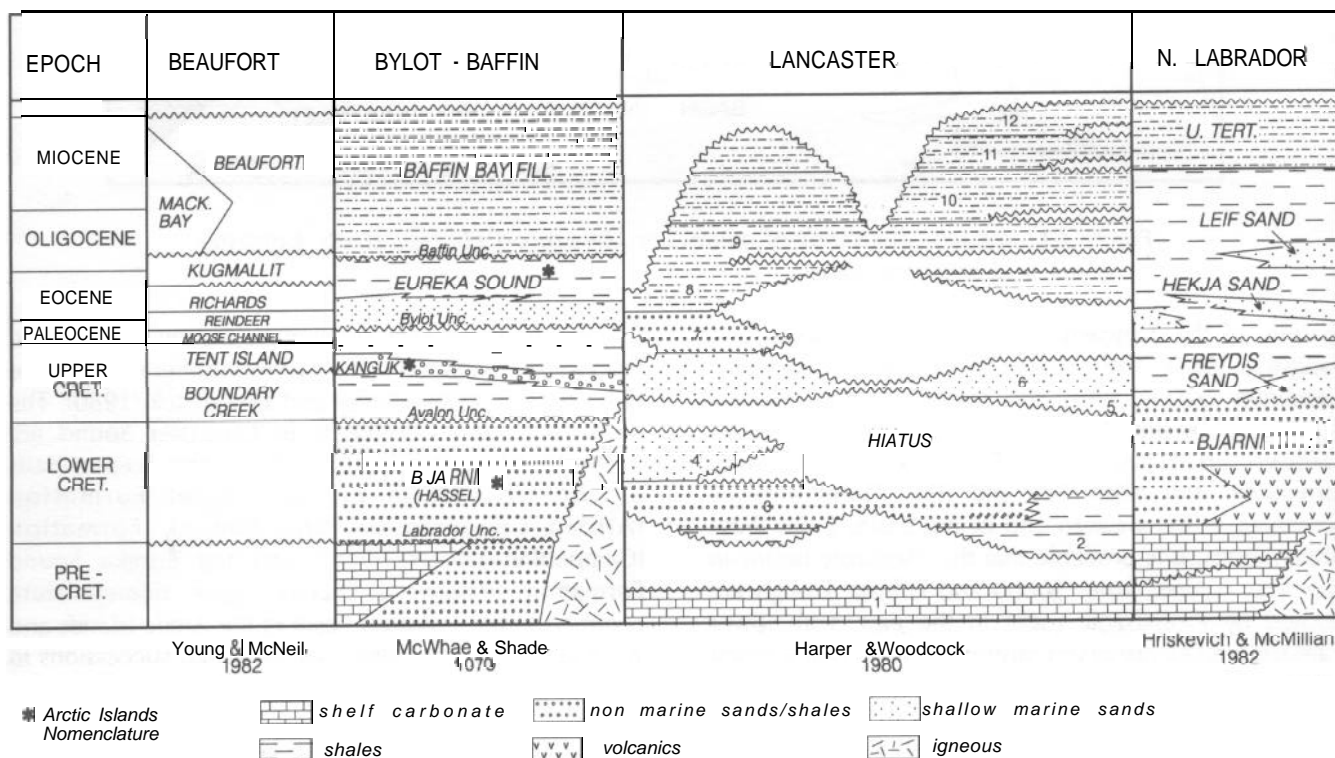


Figure 65. inferred stratigraphy of Lancaster Sound Basin and comparison with other nearby basins and the Beaufort-Mackenzie Basin (after Smith et al., 1989).

reported to have extensive intercrystalline and solution-collapse breccia porosity (McWhae, 1979). The Allen Bay and Middle Devonian Blue Fiord limestones also have potential for porosity development.

Structure, Traps and Seal

Numerous tilted fault blocks have been recognized on seismic. Most appear to have a long history of movement throughout the Cretaceous and have profoundly affected the deposition of stratigraphic intervals with reservoir potential. Many traps may therefore have a significant stratigraphic component indicated by onlap onto tilted fault blocks. High standing blocks may be truncated by unconformities within the Tertiary. Thick shale intervals in the fluvial to transitional depositional settings common in the Cretaceous and Tertiary are unlikely. Top seal across many of the high-standing fault blocks must therefore be suspect. Fault reactivation may further adversely affect seal integrity.

Source Rocks

Paleozoic source rocks may retain potential to generate hydrocarbons but lengthy exposure of the Paleozoic prior to the Cretaceous may have thoroughly oxidized potential source rocks. Source rock candidates within the Mesozoic succession may include marine shales (presence inferred from overlapping seismic sequences) and lacustrine sequences. Basin restriction by a seaward sill - possibly a recurrent feature at the mouth of Lancaster Sound - improves the possibility of source rock deposition in poorly oxygenated bottom waters. Outcrop sampling indicates that shales within the Bjarni Formation have very good gas-prone source rocks. Upper Cretaceous Kanguk shales have TOCs in excess of 2% and are potential oil source rocks.

Potential

Smith et al. (1989) rate the oil and gas potential of Lancaster Sound Basin as high, based on a review of the current state of knowledge. No new data of significance has been acquired since this study. It is clear that this basin fulfils many of the criteria of a petroliferous basin but that significant risk remains: specifically, source rock presence and maturity, seal integrity, breaching of traps and timing of migration. The similarity with the Labrador shelf, in particular the large terrestrial input to the basin, suggests that the basin may be gas rather than oil prone. However, in the absence of drilling, the basin must be considered to have significant potential for both oil and gas.

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BAFFIN BAY

Age	Cretaceous (Albian?) to Tertiary
Depth to Target Zones	Unknown
Maximum Basin Thickness.. ...	14 km (8 km average)
Discoveries	None
Basin Type	Passive margin, rifted subbasins
Depositional Setting	Fluvio-deltaic to marine
Reservoirs	?Cretaceous and Paleogene sandstones
Regional Structure	Extensional faulting, half-grabens
Seals	Marine shales
Source Rocks	Lower Cretaceous (gas prone) Upper Cretaceous, Paleocene marine shales (gas with some oil potential but barely mature)
Depth to Oil Window	3300-3800 m
Seismic Coverage	Sparse reconnaissance seismic
Area under Licence	None

Baffin Bay contains local depocentres with thick Mesozoic sedimentary sequences that have good potential for gas and oil. There is evidence of active oil seeps and petroleum source rocks. Cretaceous to Lower Tertiary formations are anticipated to have good reservoir characteristics. The basin is undrilled.

Geological Setting

Baffin Bay is the northwestern extension and terminus of the North Atlantic-Labrador Sea rift system. The progressive northward stepping of sea floor spreading in the North Atlantic resulted in graben development in the incipient Baffin Bay area in the Early Cretaceous. Oceanic crust began to form in Baffin Bay in the Paleocene but sea-floor spreading appears to have ceased in the Oligocene. Baffin Bay is bounded to the north by Nares Strait, a probable transform fault, and to the south by the Ungava transform underlying Davis Strait. Sedimentary strata are thickest along the narrow east Baffin shelf and the opposing and much broader west Greenland shelf. A major depocentre is present at the northern end of the Baffin shelf opposite the mouth of Lancaster Sound.

Sedimentation has been characterized by the influx of coarse elastic material across the rifted and rapidly foundering margin of Baffin Island. The sediments were derived from the surrounding highlands of the Baffin coast and by clastics brought from the lower Paleozoic hinterland of the Canadian Arctic Islands by major rift controlled drainage systems.

Exploration History

No wells have been drilled in Baffin Bay, with the exception of ODP site 645. In 1976-77, five wells were drilled in Davis Strait, at the southern entrance to Baffin Bay. These dry and abandoned wells are in Danish waters on the west Greenland Shelf. The Geological Survey of Greenland suggests that they failed to test prospective pre-Tertiary sequences indicated by seismic.

Seismic exploration of the northeastern Baffin shelf has been limited. The few reconnaissance programs shot are insufficient to delineate drilling prospects.

Stratigraphy (Fig. 66)

The Mesozoic sediments of Baffin Bay are probably underlain by Proterozoic rocks comparable to those now exposed on Baffin Island. Ordovician to Silurian rocks may be preserved in the offshore, but there is no seismic evidence to suggest that this is the case.

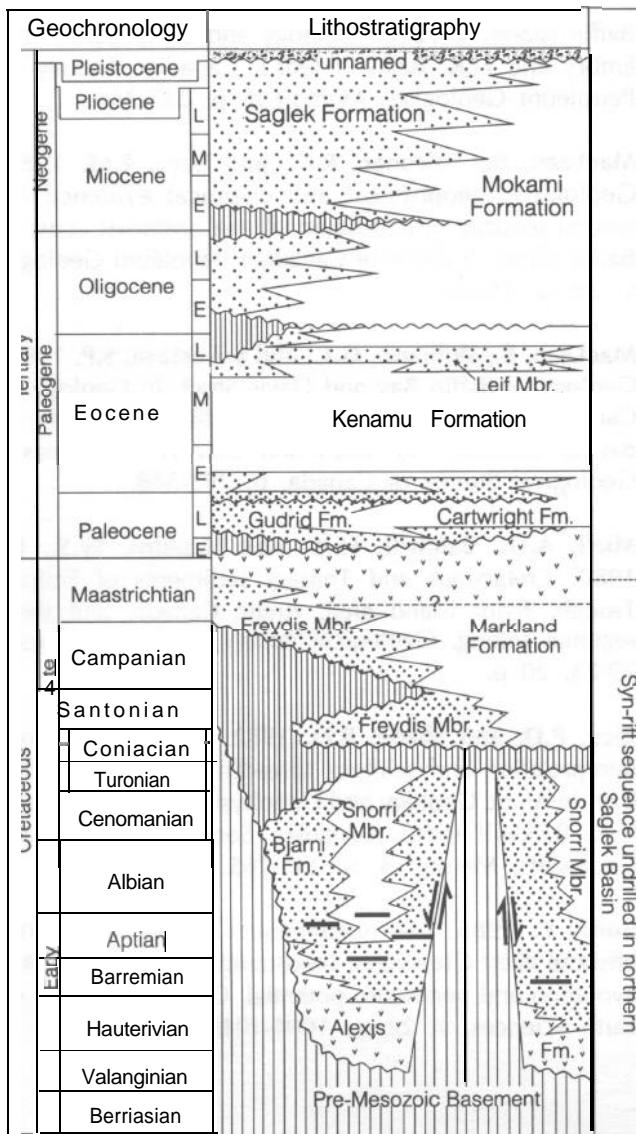


Figure 66. Generalized stratigraphy of the Baffin Bay shelf area.

The oldest Mesozoic sediments in the Baffin Bay region are Aptian to Lower Albian sandstones of the Quqaliut Formation, described by Burden and Languille (1990), north of Cape Dyer in the southern approaches to Baffin Bay. These strata are unconformably overlain by Paleocene braided stream deposits (Cape Searle Formation). The latter contains volcanic and volcanoclastic clasts formed during a violent tectonic episode, possibly the onset of sea-floor spreading in Baffin Bay. Cretaceous to Tertiary sediments also outcrop on Bylot Island and adjacent to Pond Inlet on northeastern Baffin Island. Strata of the Hassel Formation (Albian-Cenomanian), the Kanguk Formation (Campanian-Maastrichtian), and the Eureka Sound Formation (Paleocene-Eocene) are likely to be

represented as thickened successions in the offshore. The Hassel, Bjarni and Quqaliut formations are much the same age and represent early rift-fill. The Cape Searle, Eureka Sound and Cartwright formations are also contemporaneous, but differ markedly in their depositional setting.

The Hassel Formation on Bylot Island is predominantly fluvial, consisting of thick, coarse-grained sandstones and thin coals. The nonmarine fluvial Quqaliut Formation was deposited in a similar depositional setting with intermittent volcanic effusions. The lower member of the younger Kanguk Formation (> 1000 m) was deposited at a time of global marine highstand in the Late Cretaceous and represents a regionally extensive shale unit. The upper Kanguk is sandy and represents subsequent regression. The Eureka Sound Formation is 1600 m thick on Bylot Island and consists of three members of marine mudstone and sandstone and one thick member of fluvial sandstone. Lacustrine to marginal marine sediments of Paleogene age have been noted from two other localities along the east coast of Baffin Island.

Reservoirs

The Hassel Formation, upper Kanguk and Eureka Sound sandstones are potential reservoir rocks. All have good porosity and permeability in outcrop samples (in the Bylot Basin). Where age equivalents have been penetrated in the subsurface on the southeastern Baffin and Labrador shelves, favourable reservoir characteristics have been preserved.

Structure, Traps and Seal

Down-to-basin faulting characterizes the northeastern Baffin shelf. In the deeper parts of the basin, rotated fault blocks are apparent. The lower member of the Kanguk Formation is a regional top seal and drapes Cretaceous structures.

Source Rocks

Upper Cretaceous marine strata are widespread in the basin (the Kanguk and Narssamiut formations of the West Greenland shelf, although these shales are generally lean in organic matter). Samples of Campanian shale from Home Bay are rich in amorphous kerogens and these shales have potential as an oil-prone source rock. Paleocene marine shales have slightly higher organic content with potential for both oil and gas. Albian shales of the Hassel and Bjarni

formations contain terrestrially derived kerogens and are possible gas source rocks.

Subsea oil seeps in Scott and Buchan troughs (halfway along the coast of Baffin Island) are indicated by the surfacing of oil globules at several locations, as noted by several researchers (e.g., MacLean et al., 1981). The oil appears to issue from fissures close to the contact between the Tertiary or Cretaceous strata and Precambrian basement, although a more recent sampling expedition failed to recover samples of crude oil.

Potential

Most of the northeastern Baffin shelf is relatively narrow but thickens and broadens opposite the mouth of Lancaster Sound. This area is likely to contain extensive potential reservoir facies, more deeply buried (hence mature) source rocks, and large fault-bounded traps. Potential exists for both oil and gas.

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SAGLEK AND LADY FRANKLIN BASINS (SOUTHEASTERN BAFFIN SHELF)

Age	Cretaceous (Neocomian) to Tertiary
Depth to Target Zones	2.5-3.5 km
Maximum Basin Thickness	8 km
Sole Discovery	Hekja O-71 (gas/condensate)
Basin Type	Pull-apart near Atlantic-type passive margin transform
Depositional Setting	Fluvio-deltaic marine shelf
Reservoirs	Paleocene Hekja sand (middle Gudrid Member)
Regional Structure	Transpressional and transextensional faulting, horst and graben
Seals	Marine shales
Source Rocks	Upper Cretaceous, Paleocene marine shales (gas with some oil potential but barely mature)
Depth to Oil Window	3300 m (Hekja O-71)
Total Number of Wells	3
Seismic Coverage	Good reconnaissance seismic grid
Area under Licence	11,184 ha (Significant Discovery Licence at Hekja O-71)

(Water depths from 200-1 000 m, ice infested waters. Population and administrative centre at Iqaluit at head of Frobisher Bay on Baffin Island.)

Exploration has proved the Labrador Sea to be a rich hunting ground for large gas/condensate discoveries. Source rock studies also indicate potential for oil. Development is hampered by remoteness and severe ice conditions.

Geological Setting

The Saglek and Lady Franklin basins are Tertiary sedimentary depocentres lying within a zone of transform faults delimiting the northern end of the Labrador Sea. The basins are bounded to the northwest by the rising floor of Proterozoic rocks forming Baffin Island. Transtensional stress in the Late Cretaceous and Paleocene resulted in the effusion of large volumes of volcanic and igneous rocks and the development of horst and graben structures, subsequently filled and draped by late Paleocene and younger sediments. The provenance of coarse sediment lies to the west in the highlands of Baffin Island with fine grained input from a large river system draining the continental interior via the Hudson Strait.

Exploration History

Three wells have been drilled in Canadian waters offshore of southern Baffin Island: Aquitaine et al. Hekja O-71, Canterra et al. Raleigh N-1 7 and Esso HB Gjoa G-37. Five wells have been drilled in Danish waters on the Greenland side of Davis Strait, approximately 500 km to the northeast.

Seismic coverage of the Labrador and southeast Baffin shelves is good. A small number of regional lines traverse the Labrador Sea and connect with seismic shot on the west Greenland shelf.

Stratigraphy

A clastic wedge of Paleocene to Recent fluvio-deltaic and marine sandstones, interfingering with shales is up to 4000 m thick. It overlies Upper Cretaceous and Paleocene volcanic rocks above the rifted basin margin. Older rift sediments beneath the volcanic sequence have not been penetrated in the north Saglek Basin but may be present and should include the Bjarni sandstones preserved in rifted half-grabens.

Paleocene middle and upper Gudrid sandstones have been drilled in north Saglek Basin. These grade distally into lower and upper members of the Cartwright Formation (up to 1500 m). Marine shales and siltstones of the Eocene Kenamu Formation overlie and overstep the Cartwright Formation onto the basin margins. A major late Eocene unconformity truncates the Paleocene to Eocene succession over structural highs. Mokami (marine mudstones) and Saglek (predominantly sandstone) formations overlie this unconformity and constitute a lightly structured post-drift megasequence.

Reservoirs

The Hekja sandstone is a 76 m interval in the Hekja O-71 well. Net sandstone amounts to 44 m and consists of fine to coarse grained sandstone, varying from quartzose to arkosic. Although poorly sorted, feldspar dissolution has produced a reservoir rock with porosity of **16%** and permeability of 10 mD. The environment of deposition is interpreted as lower delta-plain. Other Paleogene sandstones are present in this area and may show marked variation in thickness and reservoir characteristics. Very thick sandstone reservoirs are possible in this geological milieu marked by rapid input of coarse clastics and active vertical tectonics.

Structure, Traps and Seal

High-relief structures and complex depositional systems make prediction of potential reservoir sandstone difficult in this region. A variety of large structural traps are present in the Paleogene, including flower structures in regions of local transpression, and drape across fault-bounded blocks. Marine shale tongues form effective seals.

Source Rocks

Paleocene shales have total organic contents of 1-2% in Hekja O-71. A 300 m zone has high resinite content (oil-prone at relatively low maturity levels) and a hydrogen index of 400. Older source rocks, which may underlie or inter-finger with the Upper Cretaceous and Paleocene volcanics, are likely to be gas-prone and mature. Sea-bed coring off Cumberland Sound has recovered samples of dark grey to black mudstone saturated with gas and condensate. Shallow seismic reflectors appear to be masked in this area, possibly by gas-saturated sediments (MacLean et al., **1982**).

Potential

Although source rock studies indicate some shales to have potential as oil source rocks, exploration in the Labrador Sea has shown this basin to be gas/condensate prone. Numerous large structures and the potential for thick pay intervals make large discoveries possible. Syn-rift sediments, if present, are obscured by volcanics in the Saglek Basin: thick sandstones of the Bjarni Formation are rift-fill.

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PALEOZOIC BASINS OF THE ARCTIC PLATFORM (FOXES AND SOUTHAMPTON BASINS)

Age	Early Paleozoic over Precambrian; small area of Cretaceous in Southampton basin
Depth to Target Zones	<1000 m
Maximum Basin Thickness	1000 m in the Foxe Basin, increasing to 2000 m or more in the Southampton subbasin
First Discovery	None
Basin Type	Interior, local rifting
Depositional Setting	Marine shelf
Potential Reservoirs	?Cambrian-Ordovician sandstones, carbonates
Seals	Unknown
Source Rock	Ordovician oil shales
Depth of Oil Window	Unknown
Total Number of Wells	1: Aquitaine et al. Rowley N-14
Seismic Coverage	Very limited
Area	120,000 km ²
Area under Licence	None

The Foxe Basin is an extensive but shallow Paleozoic basin, deepening to the south into the Southampton subbasin, which contains Mesozoic strata. The Ordovician has the potential for oil source rocks and minor reef development. Potential for oil is low to moderate and large accumulations are unlikely. Exploitable accumulations of gas are very unlikely, given the lack of maturity, source rock, seal and significant reservoir pressure. The deeper Southampton subbasin has a somewhat higher potential.

Geological Setting (Fig. 67)

The Foxe Basin is the northern component of the Hudson Bay Platform, separated from the Hudson Bay Basin to the south by the Bell Arch. The basin extends onshore in southeastern Baffin Island where two parallel northwest-oriented rift systems are present. The northern rift is less developed and extends across Baffin Island into Cumberland Sound. The southern rift system flanks the Bell Arch and underlies Hudson Strait and Foxe Channel. The half-graben underlying the Foxe Channel within this rift system is called the Southampton subbasin.

Exploration History

The single exploration well in the Foxe Basin, Rowley N-14, drilled in 1971, terminated in Precambrian rocks at a depth of 512 m. The well penetrated Ordovician carbonates and Cambrian sandstones.

Stratigraphy (Figs. 68, 69)

Igneous/metamorphic basement rocks are overlain by the Cambrian clastic/carbonate succession comprising the Gallery and Turner Cliffs formations. These are

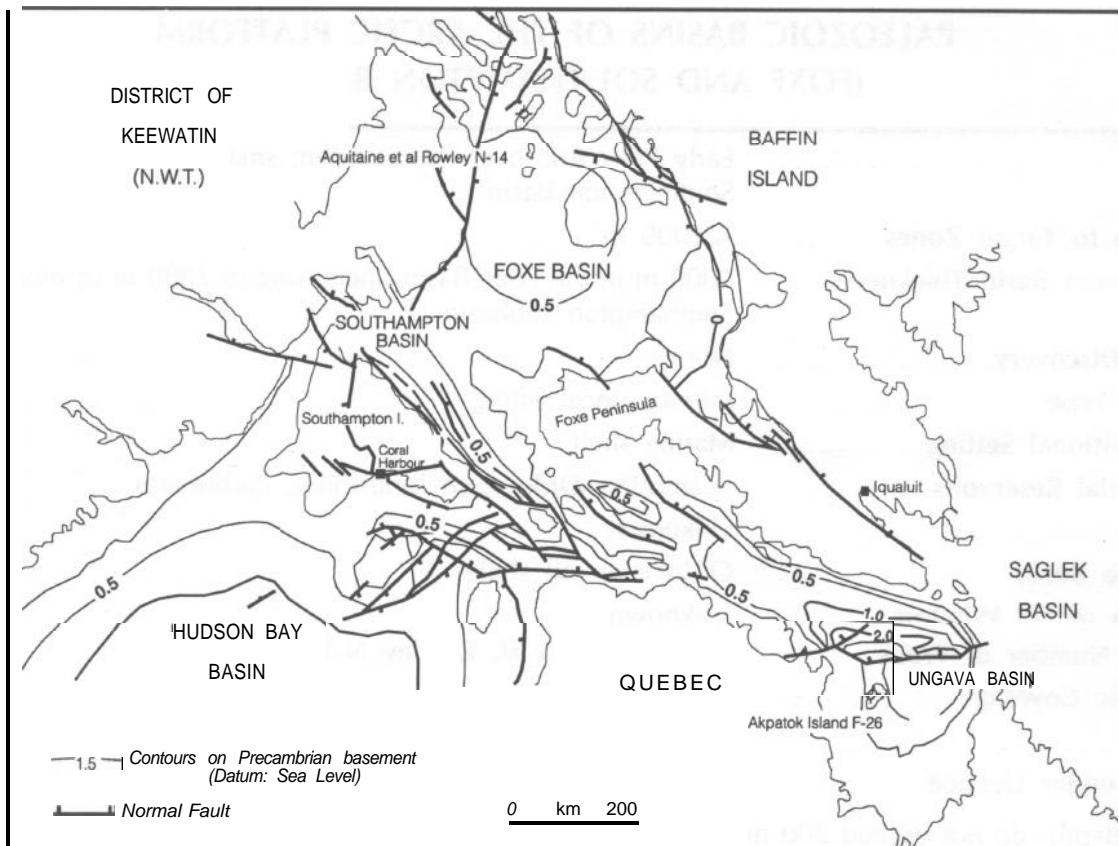


Figure 67. Regional structure of the Foxe Basin and adjacent areas (contours in thousands of metres).

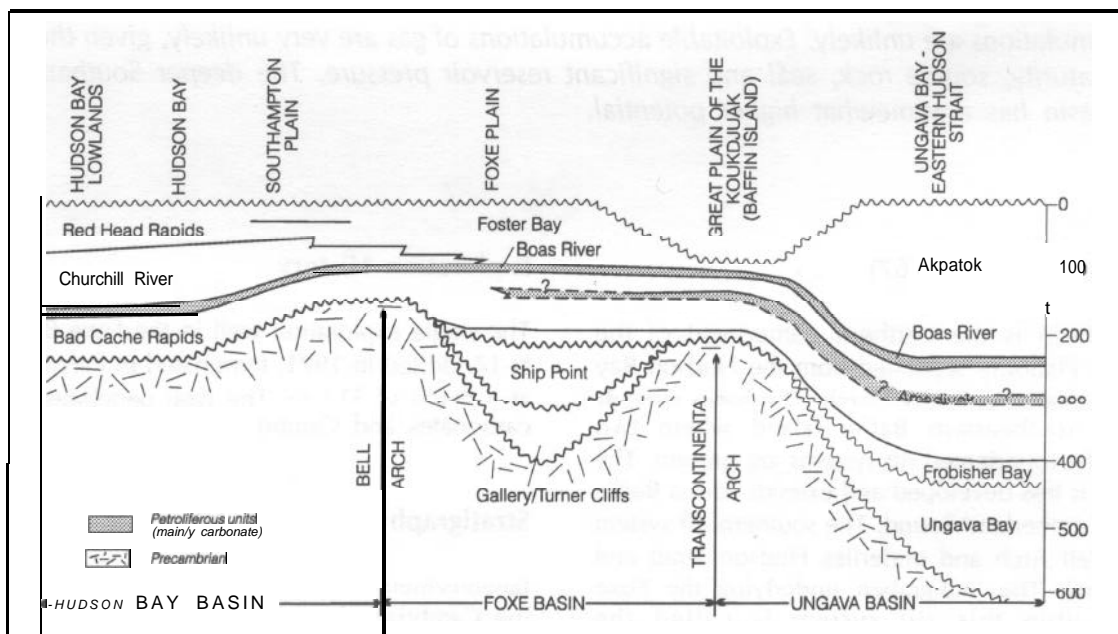


Figure 68. Stratigraphic cross-section from the Hudson Bay lowlands northwards to Ungava Bay.

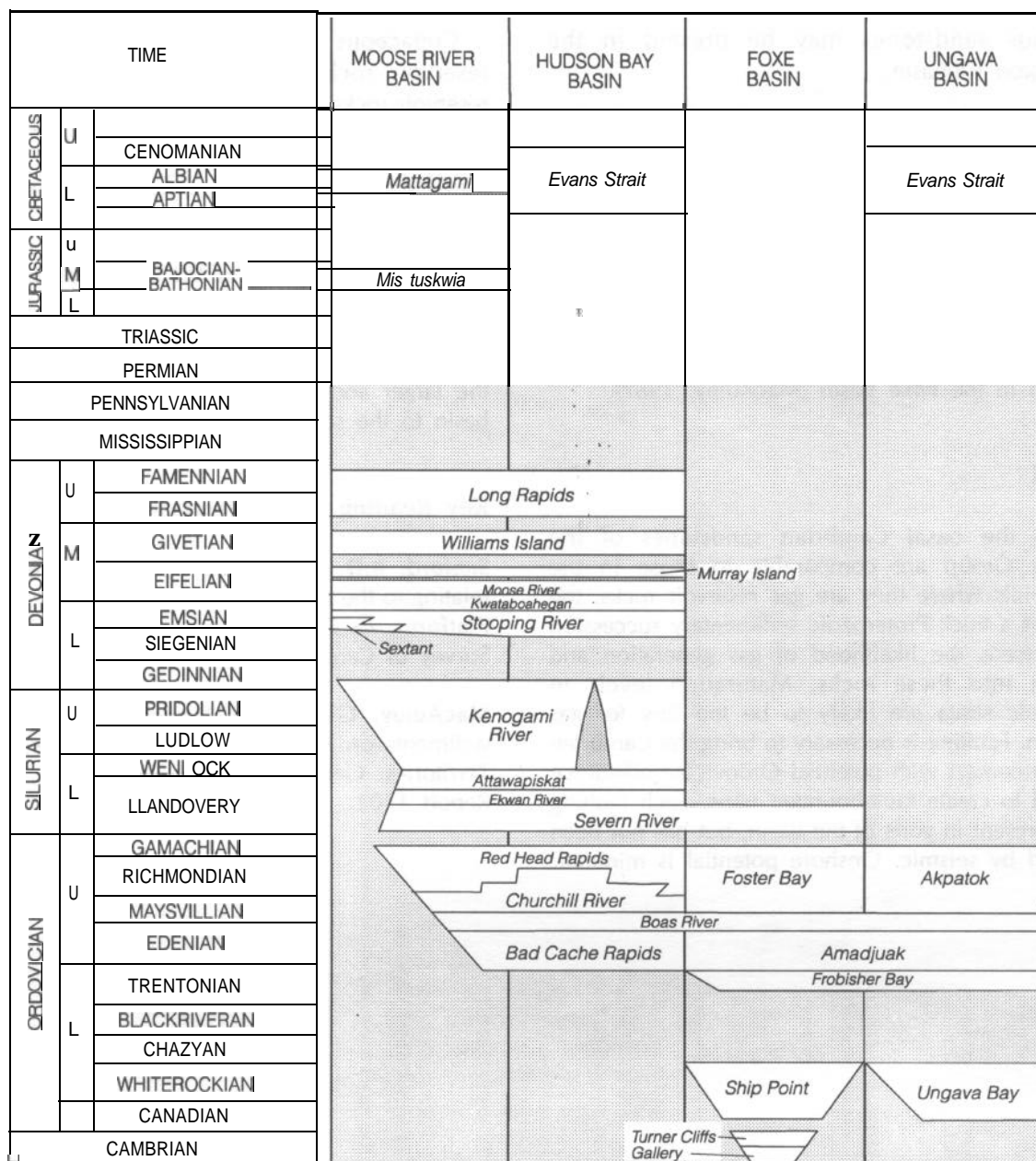


Figure 69. Stratigraphic chart for the Moose River, Hudson Bay, Foxe and Ungava basins.

overlain by the Lower Ordovician Ship Point Formation (dolostone with minor sandstone), some 80 m thick in the Rowley well. The upper Middle Ordovician to lowermost Silurian is represented in the basin by the Frobisher Bay, Amadjuak, Boas River, Foster Bay and Severn River formations – similar and probably depositionally contiguous with the equivalent succession in the Hudson Bay Basin. It is a predominantly carbonate succession.

Total thickness of the Phanerozoic succession in the Foxe Basin probably is in the order of 500 m except in

the Southampton subbasin, where a thick wedge of Cretaceous strata is preserved. As much as 2000 m of Cretaceous strata may be present, informally designated the Evans Strait formation.

Reservoir Rocks

Cambrian sandstones of the Admiralty Group have good reservoir potential. Bioherms in the Ordovician carbonate succession are possible reservoirs but are likely to be small with poorly developed porosity.

Cretaceous sandstones may be present in the Southampton subbasin.

Source Rocks

Ordovician oil shales (principally the Boas River Formation), first described from Southampton Island, are now recognized as being widespread across the Hudson Platform. Exposures on southwestern Baffin Island confirm the presence of oil shows in the Amadjuak Formation and the overlying Boas River Formation in the Foxe Basin (MacAuley, 1987).

Potential

Although the basal Cambrian sandstones of the Admiralty Group are comparable to those in the Colville Hills where they are gas reservoir rocks, the absence of a thick Proterozoic sedimentary succession greatly lessens the likelihood of gas generation and migration into these rocks. Maturation levels in Phanerozoic strata are likely to be too low for gas generation. Faulting is necessary to bring the Cambrian strata into contact with potential Ordovician oil-source rocks and to create fault-bounded traps. Such faulting may be present in parts of the basin, but has not been delineated by seismic. Onshore potential is minimal.

Cretaceous strata may contain good potential reservoir rocks comparable to Lower Cretaceous reservoir rocks in the Labrador Sea basins. Subcrop of Ordovician oil source rocks beneath the Cretaceous creates an opportunity for basal Cretaceous stratigraphic traps. Cretaceous potential is wholly offshore and restricted to the Southampton subbasin.

Potential across most of the Foxe Basin is low due to the thin sedimentary succession. In the deeper Southampton subbasin, potential is moderate. Further exploration likely awaits significant encouragement in the larger and geologically comparable Hudson Bay basin to the south.

Key Reading and References

Sanford, B.D. and Grant, A.C. 1990. New findings relating to the stratigraphy and structure of the Hudson Platform. Current Research, Part D, Geological Survey of Canada, Paper 90-1 D, p. 17-30.

MacAuley, G. 1987. Geochemistry of organic-rich sediments on Akpatok and Baffin islands, Northwest Territories. Geological Survey of Canada, Open File Report 1502.