GEOLOGICAL SURVEY OF CANADA
PAPER 92-8

PETROLEUM RESOURCES OF THE JEANNE D'ARC BASIN AND ENVIRONS, GRAND BANKS, NEWFOUNDLAND

1992

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PETROLEUM RESOURCES OF THE JEANNE D'ARC BASIN AND ENVIRONS, GRAND BANKS, NEWFOUNDLAND

PART I: GEOLOGICAL FRAMEWORK

I.K. Sinclair, K.D. McAlpine, D.F. Sherwin, and N.J. McMillan

PART II: HYDROCARBON POTENTIAL

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1992

Available in Canada through authorized bookstore agents and other bookstores

or by mail from:

Canada Communication Group — Publishing , Ottawa, Canada K1A 0S9

and from: Geological Survey of Canada offices:

601 Booth Street, Ottawa, Canada K1A 0E8
3303-33rd Street N.W.,, Calgary, Alberta T2L 2A7

A deposit copy of this publication is also available for reference
in public libraries across Canada

Cat. No. M44-92/8
ISBN 0-660-57086-6

Price subject to change without notice

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Manuscript submitted: 90.12.11
Approved for publication: 90.12.11

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ABSTRACT

A series of Mesozoic sedimentary basins extends across the broad continental shelf of Newfoundland. So far it has been demonstrated that only the Jeanne d'Arc Basin and environs contain potentially commercial quantities of oil and gas. The development in this area of hydrocarbon source rocks, reservoir rocks, source rock maturity, and hydrocarbon migration and trapping mechanisms was controlled by the cyclic development of extensional forces related to the opening of the North Atlantic Ocean.

Geophysical exploration of the Grand Banks region began in the early 1950s. The first industry seismic program for the Jeanne d'Arc Basin was undertaken by Amoco in 1965. Drilling in the Jeanne d'Arc Basin and environs began in 1971 and, after a hiatus from 1975 to 1978, drilling activity peaked in 1984. A total of 67 wells have been drilled, and over 150 000 km of seismic data have been recorded in the study area to the end of 1989.

In Part I of the report, 15 hydrocarbon exploration plays are defined by area and type of trap and by the lithostratigraphic horizon providing the reservoir facies. In Part II, seismic and well data for each play are used as input data in statistical estimations of the total and remaining hydrocarbon potential of the Jeanne d'Arc Basin and environs.

PART I: GEOLOGICAL FRAMEWORK

INTRODUCTION

Estimates of the oil and gas resources of various regions of Canada are prepared periodically by the Petroleum Resource Appraisal Secretariat of the Geological Survey of Canada. Other agencies involved in this study were Canada Oil and Gas Lands Administration (COGLA), the Canada-Newfoundland Offshore Petroleum Board (CNOPB) and the Newfoundland Department of Energy. The estimates were prepared using a probability methodology, in which each of the individual exploration plays of a region being assessed is examined for potential gas and oil resources. The method incorporates objective data derived from exploration drilling and geophysics. In addition, the subjective opinion of informed experts is used, and comparisons are made with analogues elsewhere in Canada or the world. This systematic approach to the evaluation of Canada's resources has been used since 1973, and the last series of estimates for the Jeanne d'Arc Basin and environs was prepared by Procter et al. (1983).

The present report on resources of the Jeanne d'Arc Basin marks a departure from the evaluation process used in 1983. In the earlier evaluations, the primary focus was on the preparation of a gross estimate of the total resources of the region. Over the years, the evaluation process has matured, the methodology has evolved, and the focus has expanded from the simple estimation of resource abundance to one of producing the input data for economic analysis and supply projection.

The number of plays in the Jeanne d'Arc Basin has increased since 1983, and the need for detailed geology-related estimates was recognized. A basin study group was formed to integrate all of the various types of geological, geophysical, sedimentological, geochemical, and historical information. This group consisted of: G.R. Campbell (NEB, Calgary); G. Morrell (COGLA, Ottawa); M.G. Fowler (GSC, Calgary); K.D. McAlpine (GSC, Dartmouth); S. Gower (CNOPB, St. John's); D.F. Sherwin (CNOPB, St. John's); I.K. Sinclair (CNOPB, St. John's); D. Hawkins (Newfoundland Department of Energy, St. John's).

The basin study group was responsible for the report contained herein (Part I). Part II is the actual resource evaluation conducted by a committee nominated by the Petroleum Resource Appraisal Secretariat. This committee consisted of: N.J. McMillan (GSC); R.M. Procter (GSC); G.C. Taylor (GSC); J.P. Hea (EMR); G.R. Campbell (COGLA).

The report (Part I) contains summaries of the general geology and hydrocarbon entrapment models, and is followed by a chapter on the exploration history of the Jeanne d'Arc Basin. The longest chapter deals with petroleum geology and delineation of the types of plays used in the assessment. Part II forms the final chapter and deals with the total resource estimates for the Jeanne d'Arc Basin, including implications of the new estimates with respect to discovery rate and future supply.

REGIONAL GEOLOGY

GENERAL SETTING OF THE JEANNE D'ARC BASIN

Amoco Canada Petroleum Company Ltd. and Imperial Oil Ltd. (1973), Sherwin (1973), Jansa and Wade (1975a, b), McKenzie (1981), Arthur et al. (1982), Hubbard et al. (1985), Grant et al. (1986a, b), Enachescu (1987), Sinclair (1988), Tankard and Welsink (1987), Grant and McAlpine (1990), and McAlpine (1990) have provided reviews of the Mesozoic–Cenozoic tectonic development, sedimentation, and stratigraphy of the continental margin of Newfoundland and of individual hydrocarbon-bearing structures.

The Grand Banks of Newfoundland consist of a floor of continental crust from the Appalachian Orogen that was constructed during the Late Proterozoic through the late Paleozoic. The Mesozoic–Cenozoic development is intimately related to the formation of the Atlantic Ocean and the Labrador Sea. The ocean basins off the eastern margin of North America developed sequentially as seafloor spreading propagated from south to north. In the Atlantic, south of the Grand Banks, seafloor spreading began in the Early Jurassic; in contrast, seafloor spreading did not begin east of the Grand Banks until the middle Cretaceous and extended northwestward to the Labrador Sea by the end of the Cretaceous.

Thus, at least two rift episodes affected the Grand Banks area, the North Atlantic rift (Late Triassic–earliest Jurassic) and the Iberia–Labrador rift (latest Jurassic–middle Cretaceous); these episodes were separated by a tectonically quiet period during the Middle and Late Jurassic.

The series of northeast-trending, elongate Mesozoic basins, including the Jeanne d'Arc Basin, that dominate the subsurface geology of the area (Fig. 1) took their present form during the second rift episode. At that time, the central Grand Banks formed a broad regional arch, the Avalon Uplift. A prominent peneplain, the Avalon unconformity, which developed during the second rift episode, truncates deformed sedimentary strata in the central basins and the intervening basement highs (Figs. 1, 3, 4). The lacuna represents as much as 50 to 60 million years of deformation and erosion over the central Grand Banks, but is laterally equivalent to a suite of unconformities and intervening stratigraphic units of Kimmeridgian to Albian–Cenomanian age in basins flanking the Avalon Uplift (Fig. 4). By the Late Cretaceous, complete continental separation had occurred around the Grand Banks. The whole area then subsided as an intact continental block and was buried beneath a relatively thin cover of undisturbed Upper Cretaceous and Tertiary strata, which underlie the modern shelf and slope.

The Jeanne d'Arc Basin is the deepest of the interconnected Mesozoic depocentres (Figs. 1, 2). The basin is a relatively narrow trough, trending northeast to north into the much larger East Newfoundland Basin.

Figures 2 and 3 illustrate the major tectonic elements of the Jeanne d'Arc Basin and the main features that confine the basin: a stable shelf — the Bonavista Platform — consisting of Tertiary and Upper Cretaceous strata overlying probable pre-Mesozoic rocks; a basin-bounding fault zone between the Jeanne d'Arc Basin and the Bonavista Platform; the north-northeast plunge toward the basin floor — the depocentre; and the Outer Ridge Complex, which is underlain in part by deformed Jurassic rocks equivalent to those in the basin. Deep reflection seismic data in the Jeanne d'Arc Basin reveal that the thickness of strata in the depocentre is actually about 20 km (Enachescu, 1986; Keen et al., 1987). Figures 2 and 3, based on industry seismic records, show a conservative interpretation.

Internally, the Jeanne d'Arc Basin is characterized by a series of trans-basin fault trends. The most prominent of these basin-transecting fault trends reaches from the Hibernia field southeast to the Ben Nevis structure (Fig. 2). Most of these faults terminate below or at the Albian–Cenomanian unconformity, indicating that the structural configuration of the basin was essentially established prior to the Late Cretaceous (Grant et al., 1986a).

STRATIGRAPHY OF THE JEANNE D'ARC BASIN

The stratigraphic units in the Jeanne d'Arc Basin (Fig. 4) include continental red clastic rocks, evaporites (mainly salt), and shallow marine carbonates deposited during the North Atlantic rift episode (Eurydice, Osprey, Argo, and Iroquois formations). Marine shale, carbonate, and minor sandstone were deposited in an epeiric basin during the Middle and Upper Jurassic (Downing, Voyager, and Rankin formations). The Egret Member of the Rankin Formation, an oil source rock (Swift and Williams, 1980; Powell, 1984; McAlpine et al., 1986; Creaney and Allison, 1987; McAlpine, 1990) was deposited during the Kimmeridgian, near the end of the Jurassic epeiric basin stage. Shallow and marginal marine sandstone, shale, and minor carbonate were deposited in the developing graben during the Iberia–Labrador rift episode (Jeanne d'Arc Formation to the Ben Nevis Formation), including most of the proven hydrocarbon reservoirs. Deposition of the widespread "B" Marker limestone corresponds with the onset of a period of relative basin stability, whereas the Albian Ben Nevis Formation was deposited during the last period of deformation to affect the Jeanne d'Arc Basin. Marine shale, chalky limestone, shelf sandstone, and turbidite sequences were deposited on the subsiding passive margin (Dawson Canyon, Wyandot, and Banquereau formations).

HYDROCARBON ENTRAPMENT MODEL

The Jeanne d'Arc Basin is the site of most of the significant oil discoveries off eastern Canada. The potentially commercial hydrocarbon reserves in this basin reflect the favourable combination of a mature, rich, oil-prone source rock, good reservoir beds and hydrocarbon trapping mechanisms, proper timing of trap formation, and good migration pathways.

SOURCE ROCKS

Geochemical studies conducted by the Geological Survey of Canada over the last few years on the oils and sediments of the Jeanne d'Arc Basin have helped to develop a good understanding of hydrocarbon generation there. Data from these studies show that the Egret Member of the Upper Jurassic Rankin Formation is an organic-rich marine shale that is uniquely oil-prone compared to other shales in the stratigraphic column. The data also indicate that most of the oils belong to a common genetic family and that the Egret Member was their source.

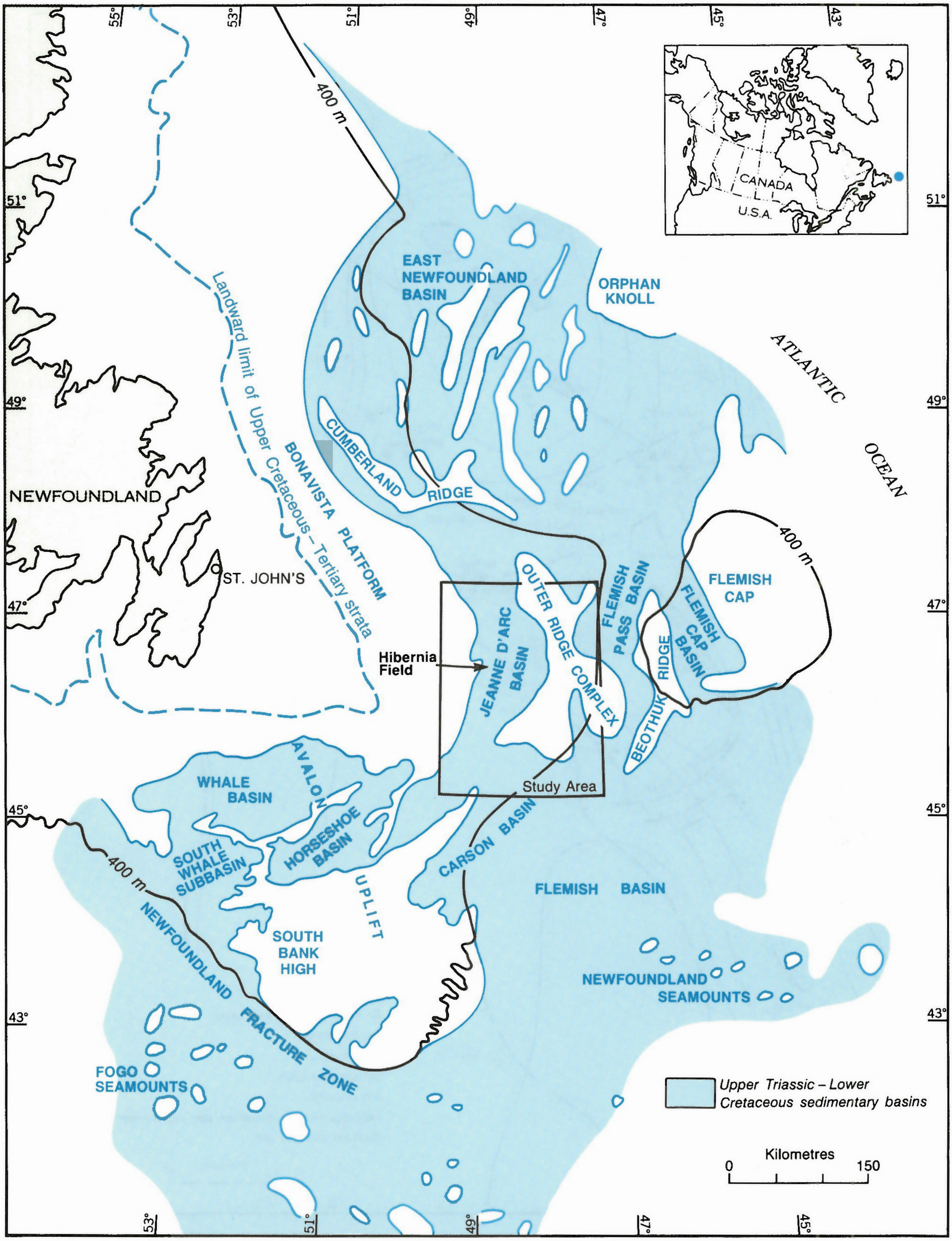


Figure 1. Sedimentary basins of the Grand Banks off Newfoundland. The area outlined in the box was evaluated for petroleum resources and is the area represented in Figure 2.

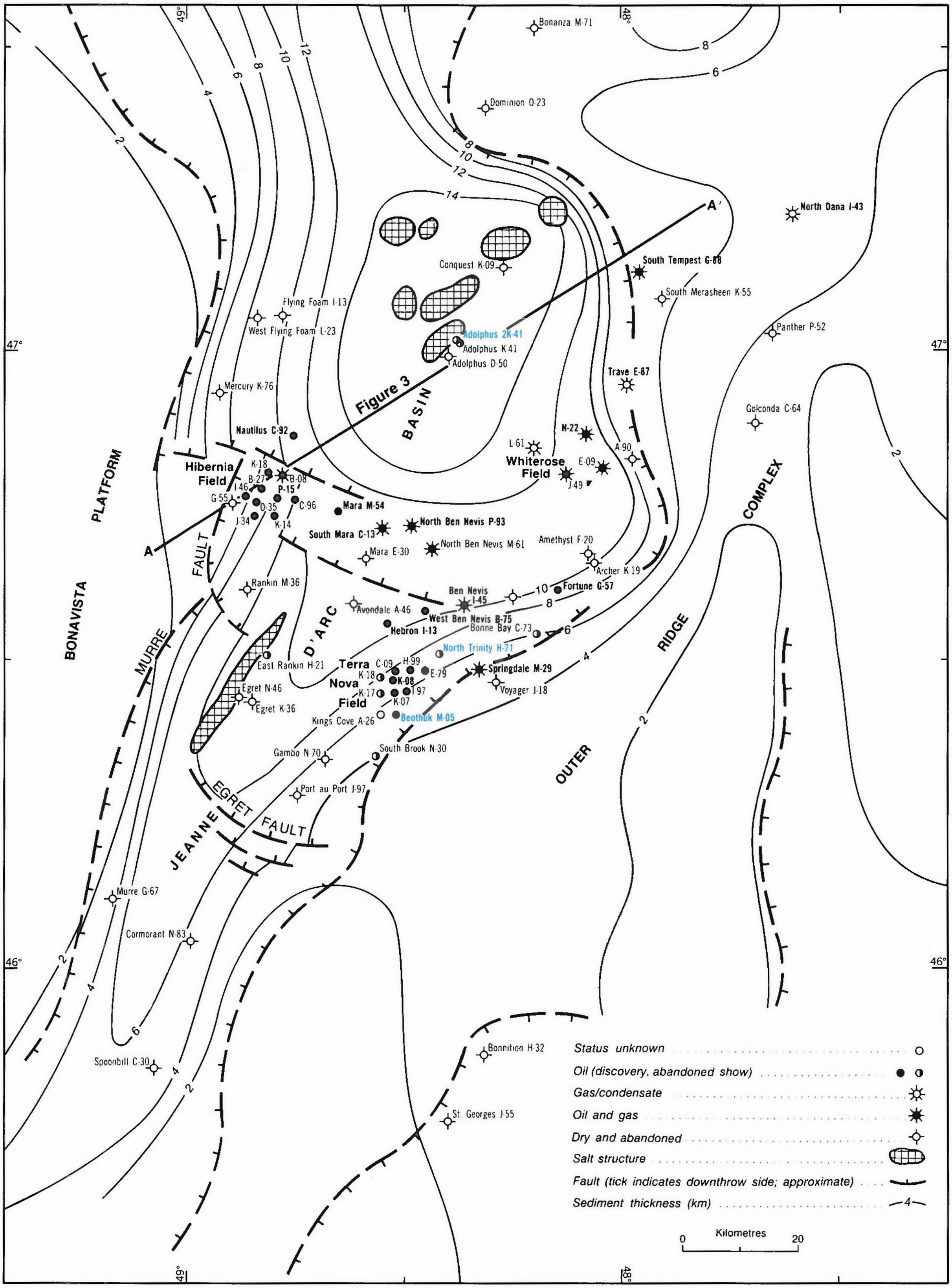


Figure 2. Jeanne d'Arc Basin and environs. All of the wells used in the evaluation are identified. Fifteen discoveries are in bold type. Three important shows are in blue type. See Table 1 and Figure 13 for detailed information. For location of study area see Figure 1.

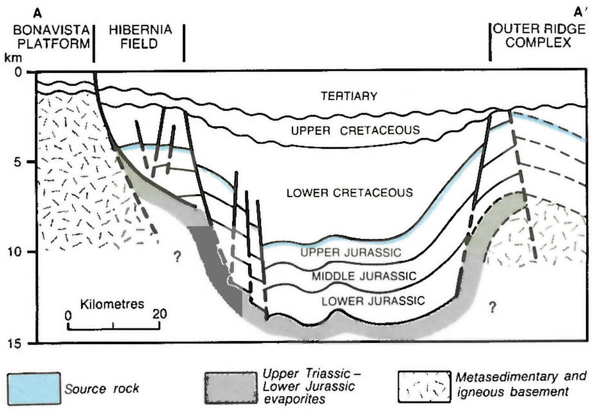


Figure 3. Schematic section across Jeanne d'Arc Basin (from Grant et al., 1986a). Location of section A–A′ shown in Figure 2.

Figure 5 shows Rock-Eval results over the source rock intervals for Rankin M-36 and Panther P-52. Similar results have been obtained for several other wells in the area. The Rock-Eval data indicate that the Egret Member is an excellent oil source rock exhibiting relatively minor regional variations in quantity and type of organic material. Rocks exhibiting only limited hydrocarbon generation potential, mainly gas, and which are of restricted geographic extent, have been identified in upper parts of the Voyager and Jeanne d'Arc formations. More sophisticated geochemical techniques for oil–oil and oil–source correlation show, however, that the Egret Member is the overwhelming hydrocarbon contributor (McAlpine et al., 1986; von der Dick et al., 1989).

OIL MIGRATION

Although Jeanne d'Arc oils are similar, they commonly differ in degree of maturity, even between separate pools within the same well (Grant and McAlpine, 1990). It is probable that different episodes of oil migration and emplacement have caused vertical variations in maturity between pools.

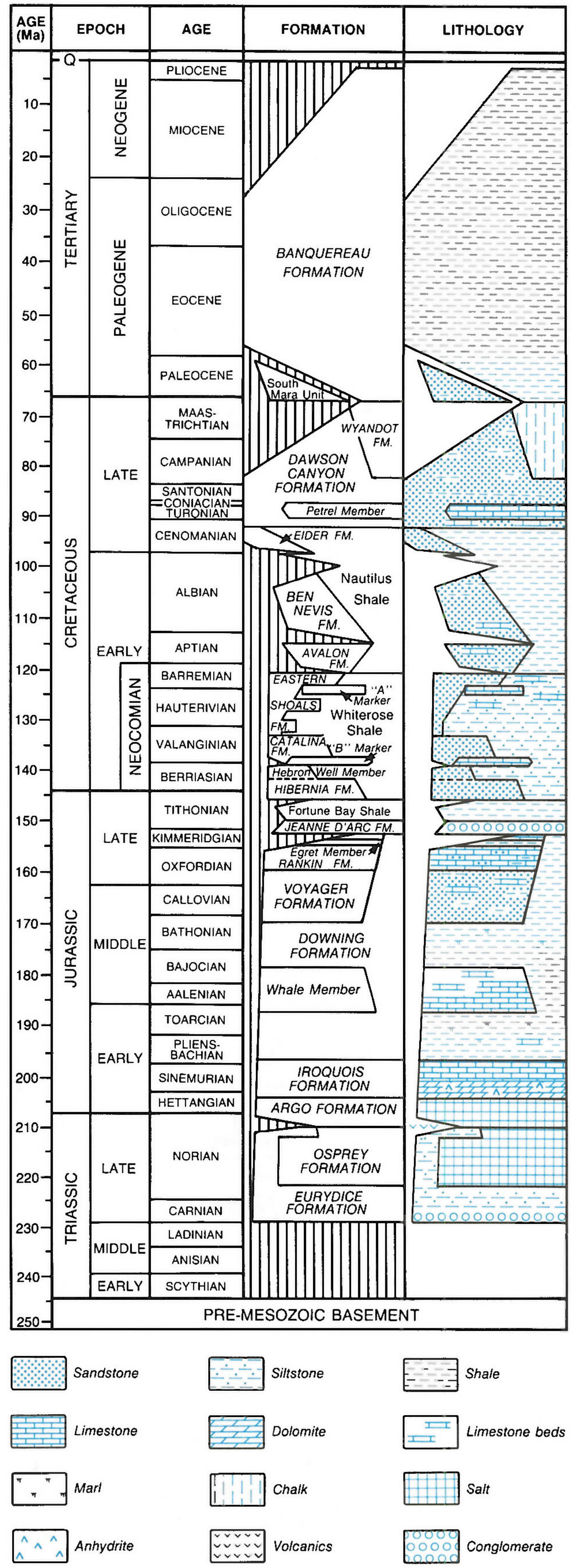


Figure 4. (Right) General stratigraphy of Jeanne d'Arc Basin adapted from Edwards and McAlpine (1988) and McAlpine (1990). The stratigraphic nomenclature in use by the CNOPB is presented in CNOPB (1988) and Sinclair (1988). It differs from that used here. In addition to other differences, the CNOPB does not recognize the presence of a Cenomanian-age Eider Formation sandstone in the Jeanne d'Arc Basin.

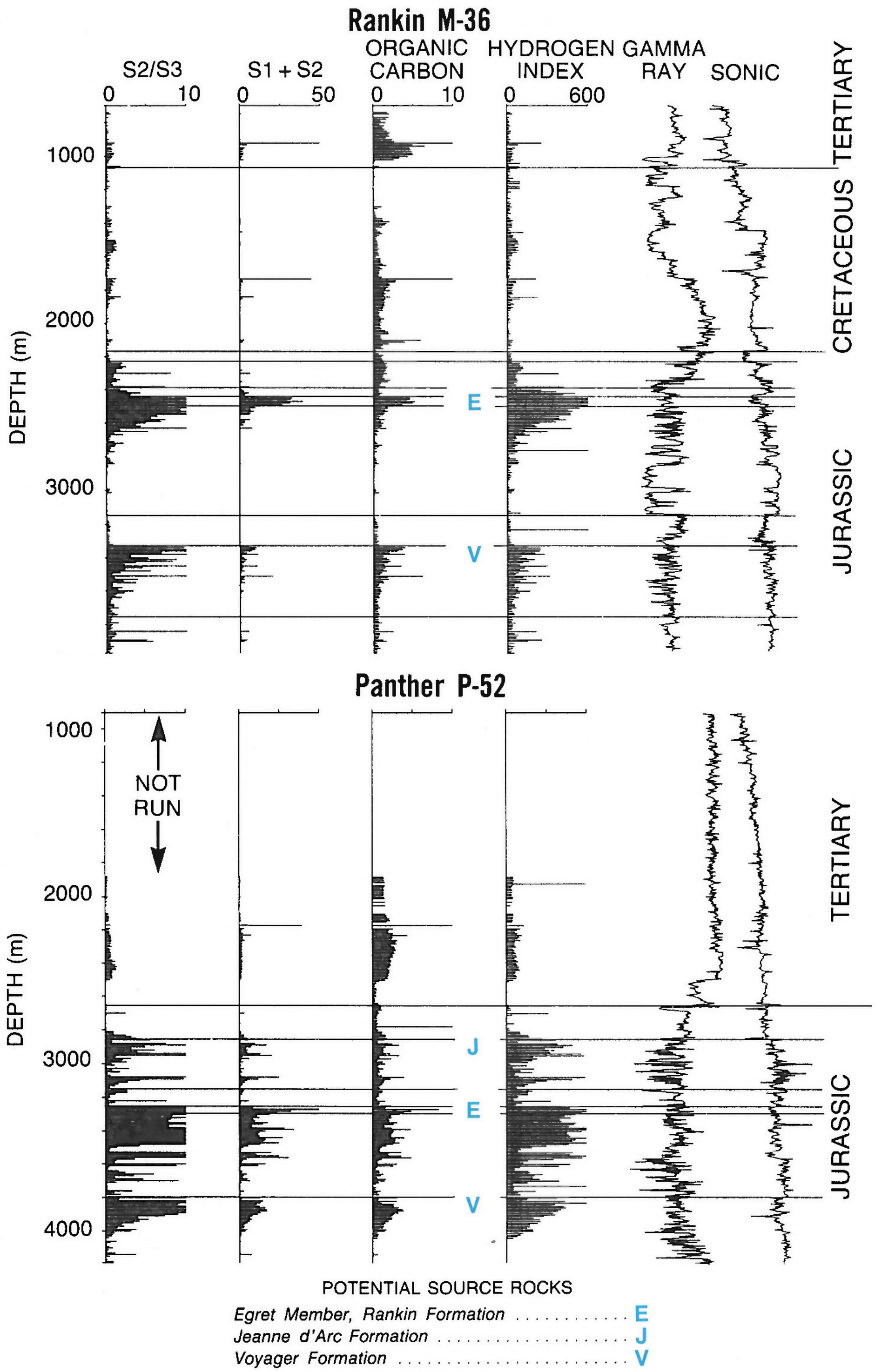


Figure 5. Rock-Eval results of Rankin M-36 and Panther P-52 obtained at the Institute of Sedimentary and Petroleum Geology, Calgary, Alberta. Well locations are shown in Figure 2. There is agreement that the V source bed in Rankin M-36 is Middle Jurassic. However, in Panther P-52 the V level may be Lower Kimmeridgian — as dated by the Bujak Davies Group (1987).

The main mechanism for oil migration may be periodic leakage along faults and fractures that have opened sporadically in response to the buildup of abnormally high fluid pressures. Overpressured zones were encountered in the first six discovery wells in the Jeanne d'Arc Basin (Fig. 6). In fact, three of these wells had to be suspended short of projected total depth when pressures approached the limits of blowout prevention. Hydrocarbons have been discovered in both the normally pressured and overpressured hydrodynamic regimes.

In the Jeanne d'Arc Basin, the top of the overpressured zone occurs generally at or near the top of the laterally continuous Fortune Bay Shale. In all cases studied, the overpressure is associated with shale compaction anomalies observed in plots of sonic transit time as a function of depth (Fig. 7).

The primary cause of the undercompaction is probably rapid loading due to sedimentation during the initial phase of the second period of rift subsidence. Thermal expansion and hydrocarbon generation may have added to the degree of overpressure (Fig. 6). Therefore, at depth, the shear strength of the undercompacted shales steadily decreases until the shales become mobile, causing faults and fractures in the overlying section. These faults and fractures become conduits for fluid escape and oil migration. This process is cyclic, because the faults close after pressure reduction, and re-open when pressure increases.

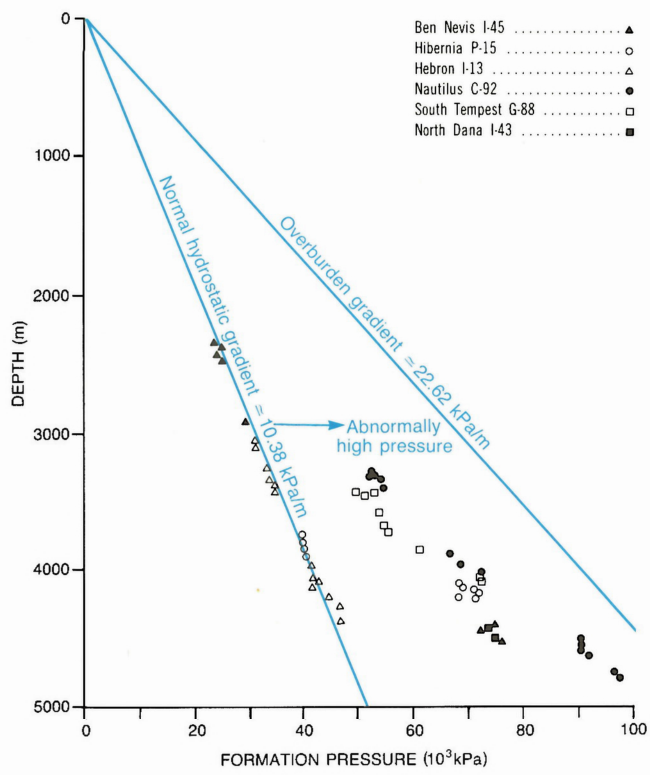


Figure 6. Plot of measured pressure *versus* depth for six discoveries in the Jeanne d'Arc Basin.

TIMING OF GENERATION

The timing of hydrocarbon generation can be estimated by determining when the source rock reached thermal maturity. The onset of oil generation for Type II kerogen occurs at a vitrinite reflectance (R_O) of about 0.5. [The Egret Member contains Type I and Type II organic matter (McAlpine, 1990).] Oil generation reaches a peak at an R_O value of about 0.8, and ends when the value is about 1.2. Figure 8 is a schematic structure map of the top of the source rock, which also shows where the source rock intersects the present day oil generative window. It is obvious that the present "sweet spot" in the Jeanne d'Arc Basin is the area surrounding the depocentre. Because the structural configuration of the Jeanne d'Arc Basin was established prior to the Late Cretaceous, the dominant process has been burial beneath a continuously accreting blanket of prograding uppermost Mesozoic and Tertiary sediments.

Numerical modelling of the timing of oil generation suggests that, near the deepest structures drilled to date, oil generation began about 100 million years ago, approximately when basin structuring was complete, and that peak generation was not reached until about 50 million years ago (McAlpine, 1990).

EXPLORATION HISTORY

INTRODUCTION

The first indication of sedimentary rocks with petroleum potential on the Grand Banks was provided in 1878 by fishermen from New England, who recovered samples of Tertiary-age rocks in their trawls and, at the request of the United States Fish Commission, brought them back home to be analyzed. Verrill (1878) documented these findings and noted that "an extensive Tertiary formation" probably constituted in large part the foundation for the whole of the outer fishing banks extending "from off Newfoundland nearly to Cape Cod".

In the early 1950s and early 1960s, ships of the Lamont Geological Observatory of Columbia University, under

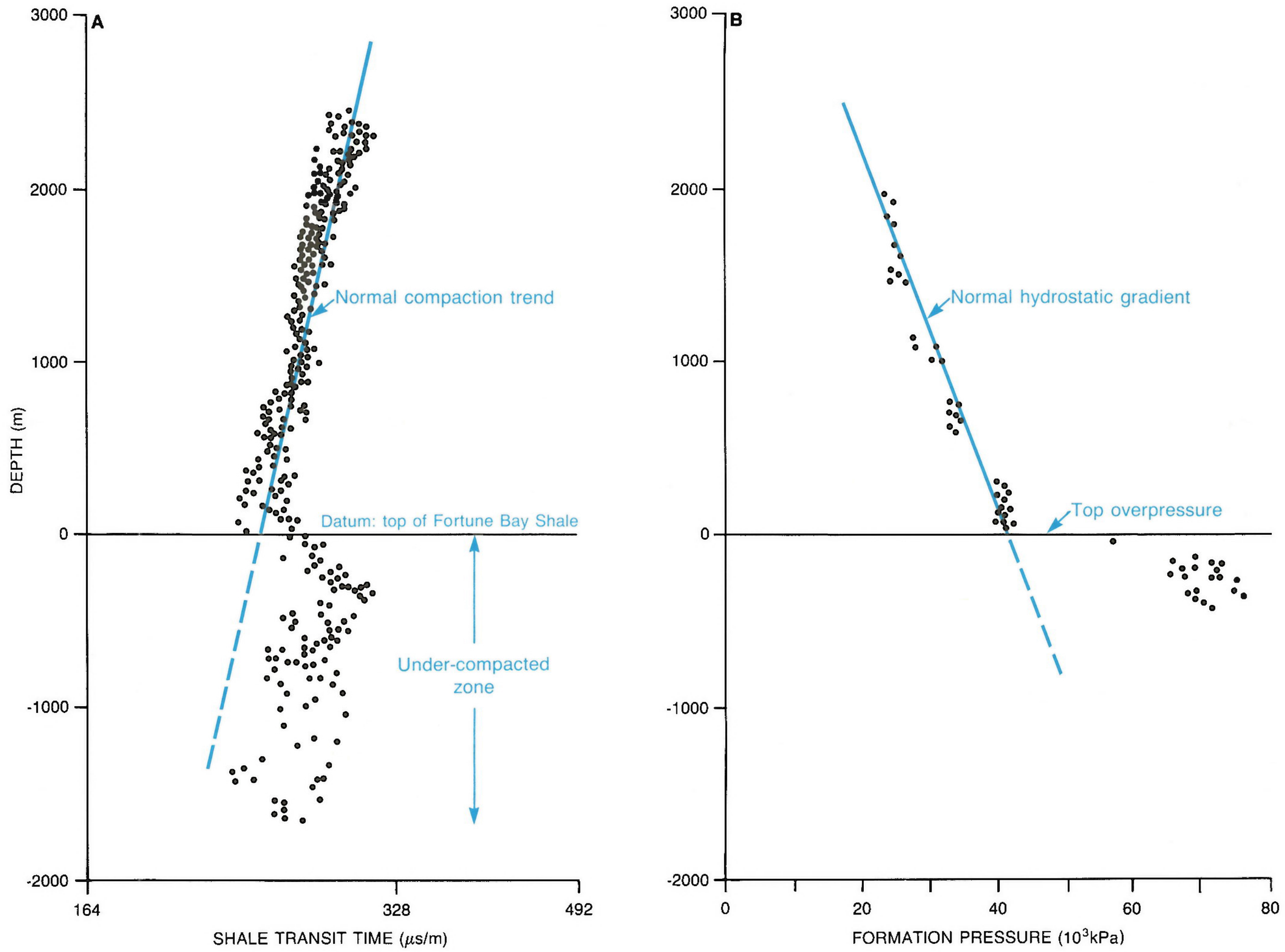


Figure 7. Plots of combined shale sonic transit times (A) and measured pressures in porous rocks (B) for Hibernia wells B-08, B-27, K-18, O-35, P-15. (Modified from Grant et al., 1986a.)

the overall direction of Maurice Ewing, carried out refraction seismic surveys on the northern, central, southwestern, and eastern portions of the Grand Banks (Press and Beckman, 1954; Bentley and Worzel, 1956; Ewing and Ewing, 1959; Sheridan and Drake, 1968). These studies confirmed that portions of the Grand Banks, including the northeast portion where the Jeanne d'Arc Basin is located, were underlain by a thick sedimentary section similar in velocity to rocks of the onshore Atlantic Coastal Plain, with all the implications of a potential petroleum province, including strata of probable Mesozoic as well as Tertiary age.

During this same period (1960–61) Lamont also carried out sea magnetometer surveys over the Grand Banks, and airborne magnetometer surveys were undertaken by the United States Geological Survey and the United States Navy Hydrographic Office (Drake et al., 1963).

Canadian government research during this period included sea magnetometer surveys on Grand Banks in 1959 and 1963, and airborne magnetometer surveys over Grand Banks and Flemish Cap in 1963, all by the Geological Survey of Canada (Bower, 1961; Hood and Godby, 1965). Work by the Bedford Institute of Oceanography, which opened in July, 1962, began on the Grand Banks with shipborne gravity studies in 1966, 1967, and 1968, sea magnetometer studies in 1967 and 1968, and seismic refraction studies in 1968. The Fisheries Research Board participated with Lamont Geological Observatory in 1960 and 1961 in refraction surveys on the Grand Banks (Sheridan and Drake, 1968). In 1969, a program of gravity, magnetics, continuous seismic profiling, and bottom dredging and coring was carried out over Flemish Cap and Flemish Pass, and revealed that Precambrian igneous rocks are exposed on the seafloor at Flemish Cap (Grant, 1971).

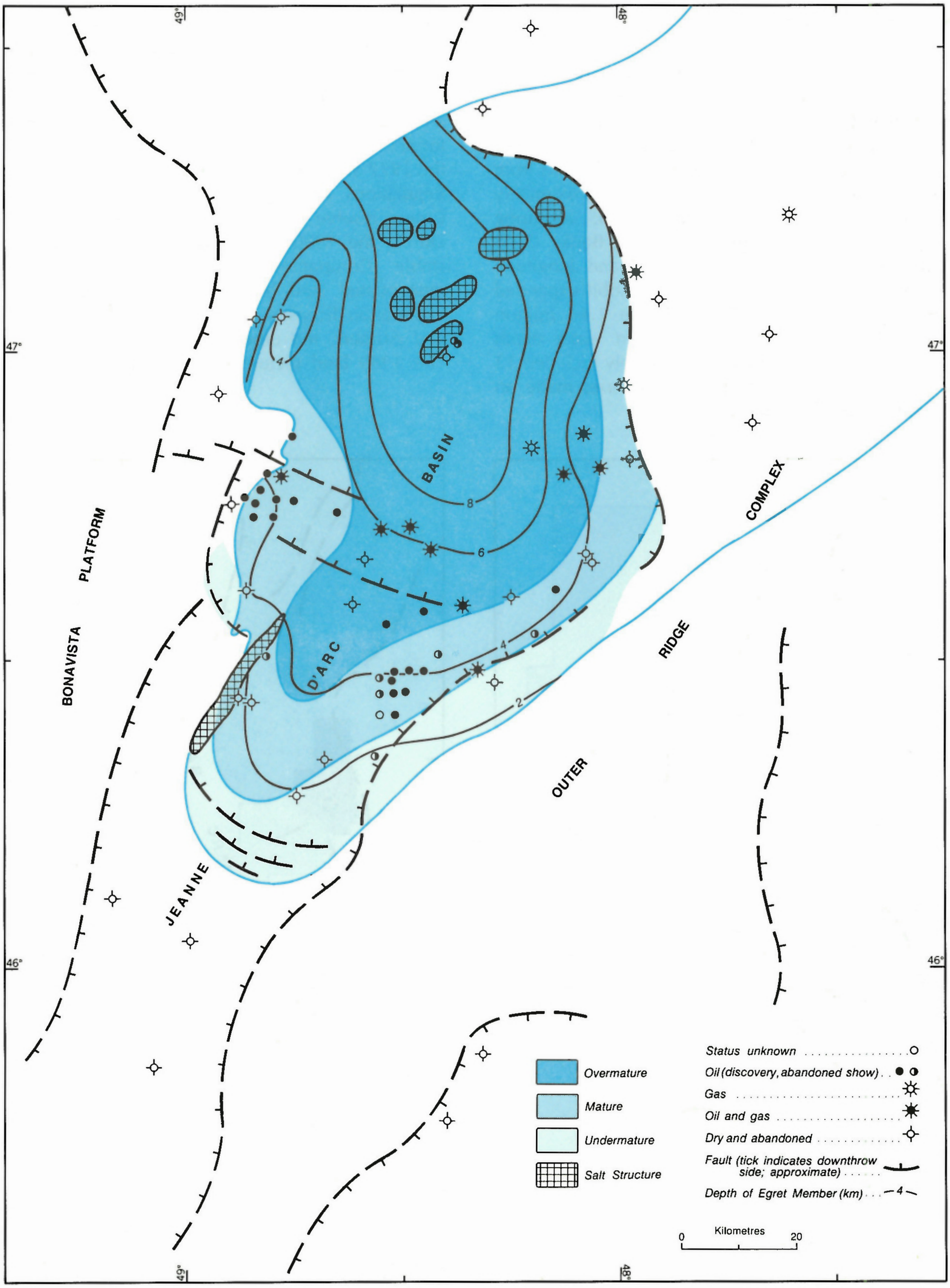


Figure 8. Maturity map of the Egret Member in the Jeanne d'Arc Basin.

LAND ACQUISITION

The first industry interest in the northeast Grand Banks area was manifested in the spring and summer of 1964, when Pan American Petroleum (later Amoco) acquired 12.67 million hectares of federal exploratory permits for oil and gas covering the whole of the Grand Banks from latitude 46°30′N to a water depth of approximately 100 m. Mobil Oil followed in January, 1965, acquiring the adjoining northeast portion of the Banks (5.45 million hectares) to latitude 49°00′N and longitude 51°00′W out to 200 m water depth. Mobil expanded its holdings in June, 1967 to include 1.44 million hectares of fringe lands out to 200 m water depth (Fig. 9). Mobil's land acquisition ultimately included 13 of the 15 significant oil and gas discoveries made on the Grand Banks, including Hibernia.

Amoco was less fortunate and, after drilling 32 consecutive dry holes, surrendered all of its lands by December, 1978, less than a year before the discovery of Hibernia. Petro-Canada subsequently acquired 6 grid areas (213 810 hectares) in the northeast corner of the former Amoco block in May, 1980 under provisions of the 1977 amendments to the Canada Oil and Gas Land Regulations, which gave Petro-Canada direct access to Crown reserve lands on a first right of refusal basis. During the 1980s, land holdings remained relatively stable. Companies exercised drilling options and renegotiated land holdings for a second term. Two exploration licenses were issued in 1989: one to BP and partners, the other to Petro-Canada and partner. The 1989 land picture is shown in Figure 10.

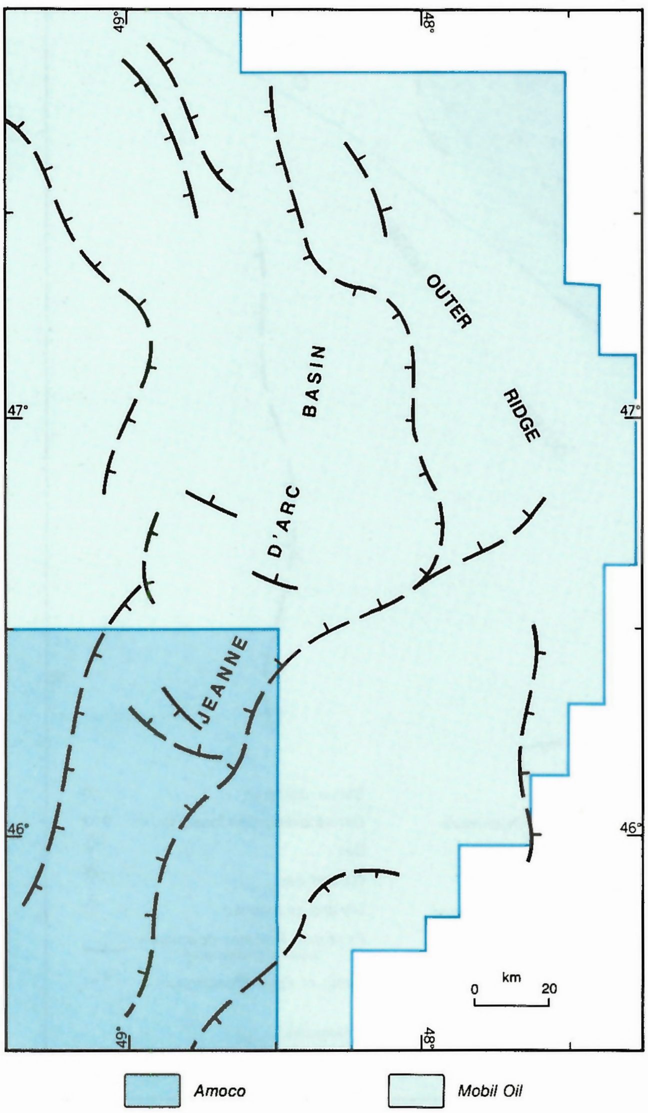


Figure 9. Land holdings, mid-1967.

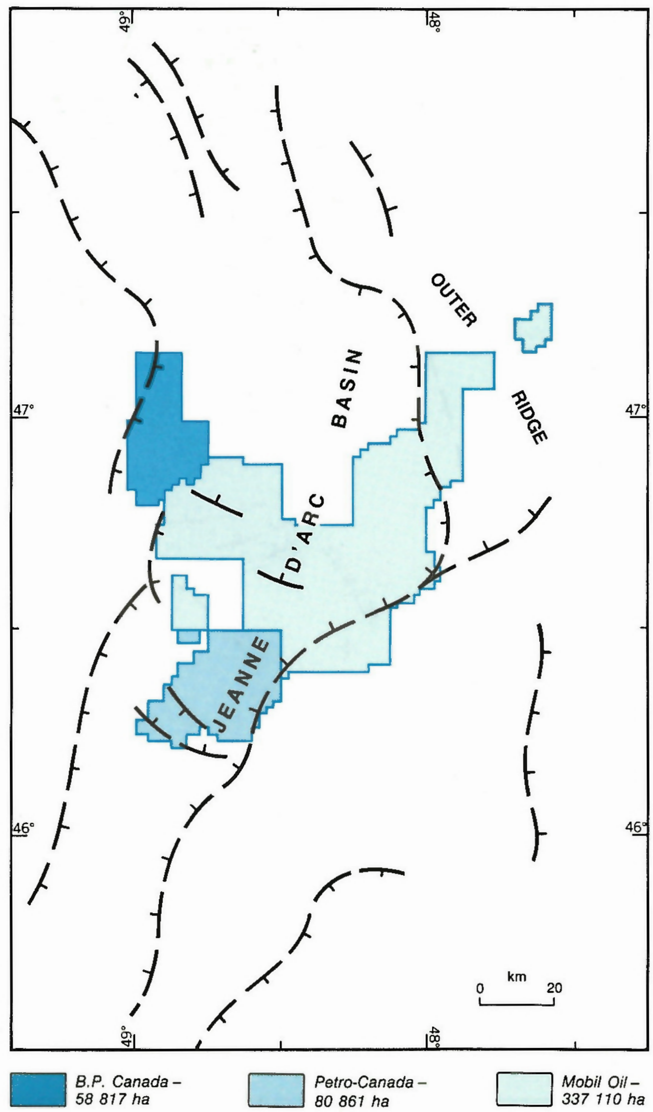


Figure 10. Land holdings, mid-1989.

GEOPHYSICAL EXPLORATION AND CORING

Geophysical exploration on Amoco's lands commenced in 1965 with seismic surveys that continued in almost every year until 1974. A deep corehole program combined with sample dredging and piston coring was carried out in 1965 on the central Grand Banks. A marine geochemical survey for detection of gas seeps was also carried out in 1965, in conjunction with the seismic program for that year.

Mobil undertook its first seismic exploration in 1966, and followed up with surveys in 1968 and in most subsequent years to 1984. Petro-Canada carried out annual seismic programs on its lands south of Hibernia in the period 1980–1984. Other companies undertaking seismic studies in the northeast Grand Banks area included Chevron (1979, 1980, 1981), Gulf (1980, 1981), ICG (1982), Canterra (1982, 1983), Husky (1981, 1982, 1984, 1985), Pan Canadian (1981, 1984), and Soquip (1983). Speculative surveys were carried out by Catalina Exploration (1970, 1971), Digicon (1970, 1972), Seiscan Delta (1972), and GSI (1971, 1972, 1980, 1981, 1982, 1984, 1985, and 1986). The seismic activity of all companies in the area of the Grand Banks and Outer Ridge from 1966 to 1988 is shown in Figure 11. More than 150 000 km of seismic data were acquired in this area. Airborne magnetometer surveys by industry were undertaken in 1964 (Amoco) and 1985 (Chevron), the latter in cooperation with the Geological Survey of Canada.

DRILLING

Drilling in the northeast Grand Banks area began in July, 1971 with the spudding of the Amoco Imperial Murre G-67 well in the southern portion of the Jeanne d'Arc Basin. Amoco drilled four additional wells in the basin, and completed their program there in August, 1974 with termination of their Egret N-46 well. These holes were part of a 32-well drilling program on Amoco's extensive Grand Banks land holdings between June, 1966 and January, 1975. All wells were abandoned as dry holes. However, a thick hydrocarbon source rock was encountered in the Egret K-36 well (Swift and Williams, 1980).

Mobil commenced drilling on its northeast Grand Banks lands in November, 1972, with the Adolphus K-41 well, located on a piercement salt dome in the northern Jeanne d'Arc Basin (Fig. 2). From the twin to this first well, Adolphus 2K-41, 31° API oil flowed during testing in September, 1973 at the rate of 43 m^3/d. Although this was not a commercial find, it was the first clear demonstration of oil potential from a well on the Grand Banks.

Mobil followed up with three additional exploratory wells, including the first wildcat on the Outer Ridge, Dominion 0-23, and an unsuccessful follow-up well on the Adolphus structure. Mobil completed this phase of its drilling program in January, 1975, on the same day that Amoco terminated their Grand Banks drilling program farther south.

Following this rather discouraging round of drilling mostly dry holes, including nine wells in the Jeanne d'Arc Basin and one on the Outer Ridge, activity in the area went into a slump, with no drilling and very little seismic activity for four and a half years. Although Amoco's lands were allowed to expire during this period, Mobil sought the means to retain its holdings.

In January, 1978, most of Mobil's northeast Grand Banks exploratory permits expired and, in accordance with the 1977 amendments to the Canada Oil and Gas Land Regulations, four special renewal permits (SRPs) were negotiated for these same lands, now reduced to 1.67 million hectares after high-grading.

Under the new terms of the regulations, two factors were significant in determining subsequent events. Firstly, a well had to be drilled on each of the four SRPs over a four-year period. Secondly, Petro-Canada had the option to acquire a 25 per cent working interest in these lands; this they proceeded to do. Given the results of previous drilling, Mobil was reluctant to proceed on its own, and went the "farmout" route. The first of the required wells, Hibernia P-15, was spudded in May, 1979, with Chevron, Columbia Gas, and Gulf (Gulf had previously been a 25 per cent partner with Mobil) assuming Mobil's share of costs on a farm-in basis, and Petro-Canada participated at its full 25 per cent interest. On September 21, 1979, Chevron reported that its Hibernia wildcat had flowed 32° API oil on test.

Subsequent testing of two shallower zones also yielded good flow rates. In January, 1980, after final testing, the well was reported to be capable of producing at the rate of 3180 m^3/d, the most productive oil well in Canada to that date.

The success at Hibernia, of course, ushered in a whole new phase of oil exploration in offshore Newfoundland, a phase which is now coming to a close. Since Hibernia P-15, 27 wildcats have been drilled in the Jeanne d'Arc Basin, resulting in 11 more discoveries of oil, or oil and gas, at a discovery rate of

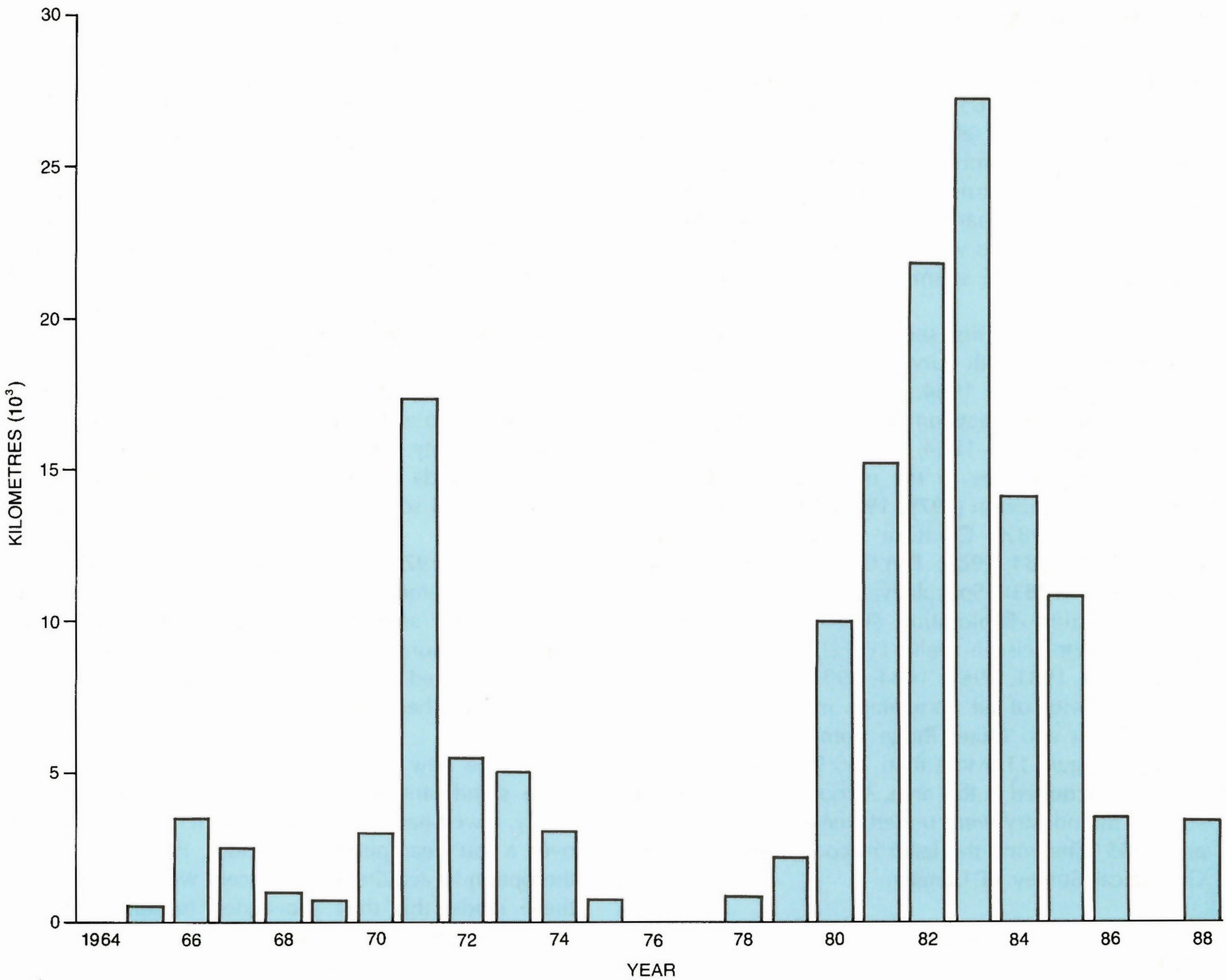


Figure 11. Amount of seismic activity by year in the Jeanne d'Arc Basin and Central Ridge area, 1964–1988.

close to 2 in 5. Twenty-one delineation wells have been drilled during the same period, including 9 at Hibernia, 6 at Terra Nova, 4 at Whiterose, 1 at North Ben Nevis and 1 at Hebron. In addition, 8 new wildcats have been drilled on the Outer Ridge, resulting in one discovery of oil and gas and two of gas, none of which has been followed up by delineation wells. This drilling activity is indicated in Figure 12.

SIGNIFICANT DISCOVERIES

As the above drilling summary notes, there have been 15 significant hydrocarbon discoveries made in the review area, including 12 in the Jeanne d'Arc Basin (6 oil, 6 oil and gas) and 3 on the Outer Ridge (2 gas, 1 oil and gas). These are described below in chronological order of their discovery. Estimates of recoverable resources in these discoveries are shown in Table 1 (CNOPB, 1989). Their locations are highlighted in Figure 2.

Hibernia

The Hibernia field located on the western flank of the Jeanne d'Arc Basin was discovered in 1979 by Chevron with the drilling and testing of the Chevron et al. Hibernia P-15 well. Tests of three separate sandstone zones in the well produced the following results: 90 m^3/d of 31.4° API oil from 5 m of net pay in the Jeanne d'Arc Formation at 4413–4434 m; up to

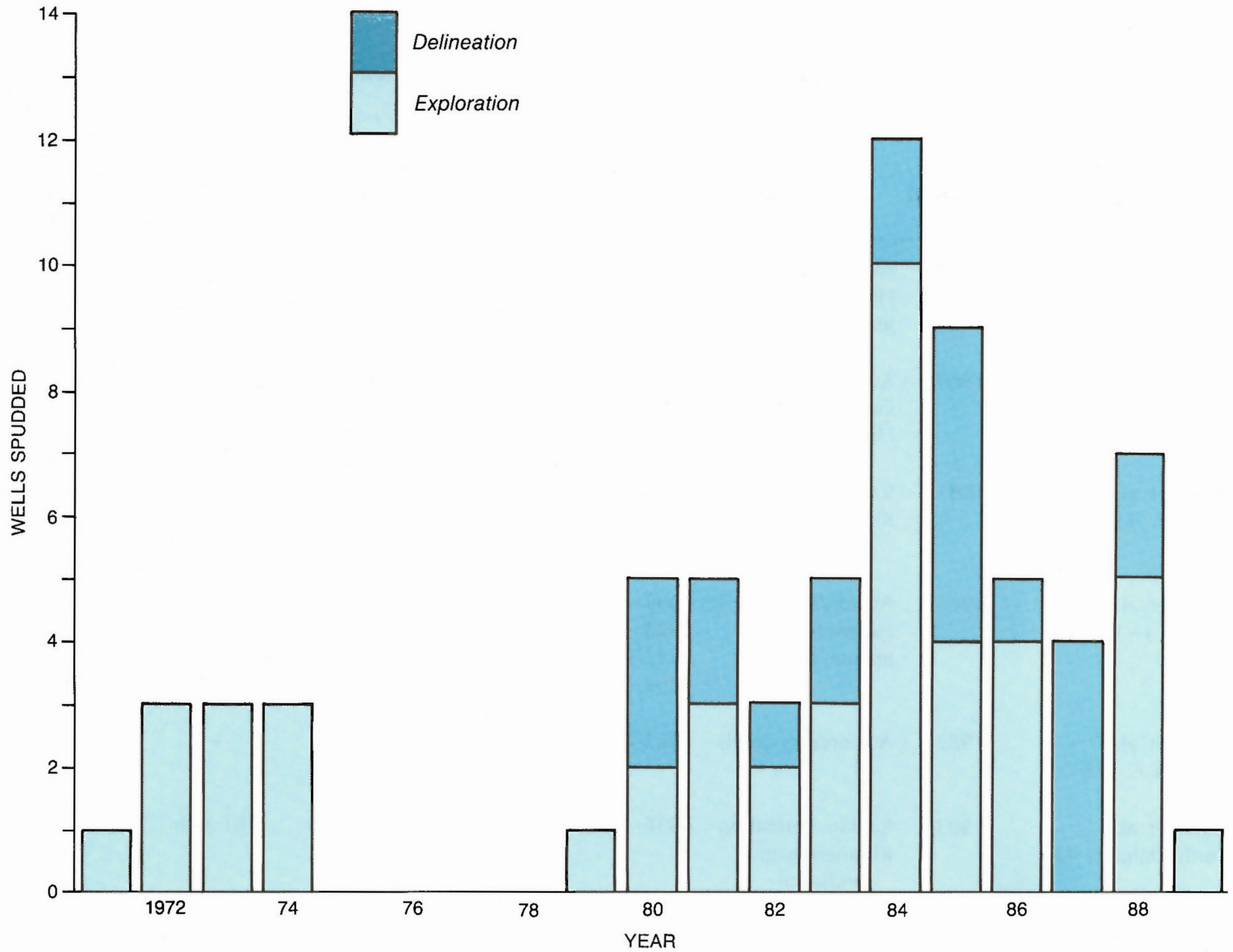


Figure 12. Number of wells drilled per year in the Jeanne d'Arc Basin area, 1971–1989.

592 m^3/d of 32.3–33.5° API oil from 47 m of net pay in the lower zone of the Hibernia Formation at 3742–3858 m; and 185 m^3/d of 30.1° API oil from 8.2 m of net pay in the Avalon/Ben Nevis formations at 2422–2443 m.

The structure that was tested by the Hibernia P-15 well was formed by Tithonian to Lower Cretaceous rollover into the major basin-bounding Murre Fault, combined with Aptian–Albian northwest-southeast listric faulting along the Trans-Basin Trend.

After the discovery at Hibernia P-15, nine delineation wells were drilled. One of these, G-55, was dry and defined the southwestern limit of the field against the Murre Fault. Drilling has indicated a probable oil/water contact in the Avalon/Ben Nevis reservoir at 2602 m depth, and two separate oil/water contacts in the Hibernia reservoir, at 3862 m in P-15, and at 3930 m in K-14 and B-27. A condensate-rich gas cap was encountered in the Hibernia reservoir in the B-08 well above 3544 m depth.

Most of the oil reserves in the field (69–76%) are contained in the Upper Jurassic (Tithonian) to Lower Cretaceous (Berriasian) Hibernia reservoir, a fluviodeltaic sequence of stacked channel sandstones with good lateral and vertical continuity. Most of the remaining reserves are in the Lower Cretaceous (Barremian to Albian) Avalon/Ben Nevis reservoir, a more complex sequence of offshore bars, storm deposits, and sheet-type sands that exhibit rapid lateral changes in thickness and reservoir quality. Only minor, probably noneconomic oil accumulations have been found in the Jeanne d'Arc and Catalina reservoirs.

TABLE 1

Discoveries in the Jeanne d'Arc Basin and environs

Discovery Well (Operator)	Year Discovered	Reservoir Formation	Interval (m)	Net Pay (m)	Recovery Oil (m^3/d)	Recovery Gas (m^3/d)	Oil/ Condensate Gravity (°API)
Chevron et al.	1979	Avalon/Ben Nevis	2422–2443	8.2	185	–	30
Hibernia P–15		Hibernia	3742–3858	47	592	–	32–33.5
(Mobil)		Jeanne d'Arc	4413–4434	5	90	–	31
Mobil et al.	1980	Avalon/Ben Nevis	2378–2445	–	Minor	–	20–25
Ben Nevis I–45		Eastern Shoals	2883–2894	4	condensate 42	282 569	48
		Hibernia	4535–4550	15	254	340 311	39
Mobil et al.	1981	Rankin Formation	3826–3834	5	23	45	39
South Tempest		Kimmeridgian	4041–4049	5	30	9 684	41
G–88		sandstone	4109–4117	2	199	140 734	42
Mobil et al.	1981	Avalon/Ben Nevis	1863–1915	36	121	–	19
Hebron I–13		Hibernia	2923–2940	31	354	–	29
		Jeanne d'Arc	3842–3857	5	488	–	31
			4368–4381	5	–	369	36
Mobil et al. Nautilus C–92	1982	Avalon/Ben Nevis	3325–3336	5.6	418	–	31
Mobil et al. North Dana I–43	1983	Rankin Formation Kimmeridgian sandstone	4536–4548	10.4	Condensate 46	361 606	53
Petro-Canada et al.	1984	Jeanne d'Arc (upper reservoir)	3329–3336	4	174	–	32
Terra Nova K–08		Jeanne d'Arc (main reservoir)	3380–3423	41	616	–	33
		Rankin Formation	3530–3544	8	104	–	32
Canterra PCI et al. Beothuk M–05 (step out from Terra Nova in a separate reservoir)	1985	Jeanne d'Arc (upper reservoir)	3022–3061	8.5	228	17 390	29
Husky–Bow Valley et al. Trave E–87	1984	Hibernia	2144–2248	9	Condensate 83	506 871	69
Mobil et al.	1984	Avalon/Ben Nevis	2926–2932	27.4	Condensate 105	399 261	59
South Mara C–13			2952–2958	6.2	276	–	35
Husky–Bow Valley	1984	Avalon/Ben Nevis	2663–2695	34.8	Condensate 107	604 734	56
et al. Whiterose		Eastern Shoals	2725–2727	1.5	–	40 125	–
N–22		Hibernia	3542–3575	7.6	87	–	32

Discovery Well (Operator)	Year Discovered	Reservoir Formation	Interval (m)	Net Pay (m)	Recovery Oil (m^3/d)	Recovery Gas (m^3/d)	Oil/ Condensate Gravity (°API)
Husky–Bow Valley et al. Whiterose L-61 (step out from N-22 in a separate reservoir)	1986	South Mara unit (Paleocene)	2527-2534	5	Condensate 69	336 970	70
Petro-Canada et al. West Ben Nevis B-75	1985	Avalon/Ben Nevis	2002-2015	4.2	97	–	28
		Eastern Shoals ("A" Marker)	2445-2465	14.6	235	–	23
		Jeanne d'Arc (upper reservoir)	4498-4507	12.8	380	–	34
Mobil et al. Mara M-54	1985	South Mara unit (Paleocene)	1852-1857	5	99	–	22
		Dawson Canyon	2403-2409	3	122	–	20
Husky–Bow Valley et al. North Ben Nevis P-93	1985	Avalon/Ben Nevis	3062-3067	15.4	Condensate 87	479 630	52
			3080-3095	18	447	–	34
Husky–Bow Valley et al. Fortune G-57	1986	Hibernia	3989-4003	7.4	156	–	36
			4031-4040	6	134	–	35
		Rankin	4417-4429	6.2	678	151 189	35
Texaco et al. Springdale M-29	1989	Confidential	~1300	–	–	331 000	–
		Confidential	~1500	–	62	–	14

Ben Nevis

The Ben Nevis discovery was made in mid-1980 by drilling and testing of the Ben Nevis I-45 well located in the Jeanne d'Arc Basin, 36 km southeast of Hibernia. The well flowed 39° API oil at 254 m^3/d from 15 m of net pay in Hibernia Formation sandstone at 4535–4550 m, with gas at 340 311 m^3/d. A zone in the Eastern Shoals Formation at 2883–2894 m with 4 m of net pay flowed gas at 292 569l m^3/d with 48.1° API condensate at 42 m^3/d. Four tests were run in the Ben Nevis Formation sandstone at 2378–2445 m, but only minor amounts of oil were recovered in the test string.

The structure tested is a domal closure on the tilted, downthrown side of a synthetic, listric fault, part of the Trans-Basin Fault Trend. Reservoir quality in the Hibernia Formation is low, due to increased cementation with depth of burial.

The very fine grained and shaly upper portion of the Ben Nevis Formation is thick due to deposition on a subsiding block bounded to the southwest by a then active, down-to-the-basin, listric growth fault.

South Tempest

The South Tempest discovery was made in early 1981 with the drilling and testing of the South Tempest G-88 wildcat well, located on the Outer Ridge 70 km northeast of Hibernia. The well flowed oil and gas on tests of three separate zones within a sandstone facies of the Upper Jurassic Rankin Formation: 199 m^3/d of 42° API oil and 140 734 m^3/d of gas from 2 m of net pay at 4109–4117 m; 30.5 m^3/d of 40.7° API oil and 9684 m^3/d of gas from 5 m of net pay at 4041–4049 m; and 23 m^3/d of 39.4° API oil and 45 m^3/d of gas from 5 m of net pay at 3826–3834 m.

The structure is a tilted fault block on the north plunge of the Outer Ridge, with updip closure provided by a north-dipping fault.

Hebron

The Hebron oil field was discovered in mid-1981 by drilling and testing of the Hebron I-13 wildcat, located in the Jeanne d'Arc Basin, 28 km southeast of Hibernia. The well flowed oil on tests of four separate sandstone zones: 369 m^3/d of 36° API oil from 4.9 m of net pay in the basal Jeanne d'Arc sandstone at 4368–4381 m; 488 m^3/d of 31° API oil from 5 m of net pay in a stray sandstone within the upper Jeanne d'Arc at 3842–3857 m; 354 m^3/d of 29° API oil from 30.9 m of net pay in the Hebron Well Member of the Hibernia Formation at 2923–2940 m; and up to 121 m^3/d of 19° API oil from 35.6 m of net pay in the Ben Nevis Formation at 1863–1915 m.

The Hebron structure is a horst and graben combination along the Trans-Basin Fault Trend. The discovery well was spudded in the graben and intersected the southern bounding fault of the horst within Whiterose shales. The Ben Nevis productive reservoir is thus located within the graben, but the lower three productive reservoirs are within the horst block. The Ben Nevis reservoir remains to be tested on the horst block where there is low risk potential for oil in good quality reservoir sandstone. Low API oil gravities within the Ben Nevis Formation in I-13 are thought to be due to biodegradation or water-washing adjacent to the intersected fault. One delineation well has been drilled on the Hebron structural complex: North Trinity H-71, located within the graben 7 km southeast of the I-13 discovery, was drilled in 1985. The well was a dry hole, with only minor amounts of oil recovered from the lower zone of the Hibernia Formation.

Nautilus

The Nautilus discovery was made in mid-1982 with the drilling and testing of Nautilus C-92, located 6 km north of Hibernia. Oil of 31.3° API flowed at 418 m^3/d on tests of the Avalon/Ben Nevis Formation sandstone (5.6 m net pay) at 3325–3336 m. The structure is the down-dropped, northern portion of the Hibernia rollover anticline, which subsided nearly one kilometre along the Nautilus Fault (part of the Trans-Basin Fault Trend) in Aptian time. The Avalon/Ben Nevis reservoir is overpressured and very poorly developed in the well, which is located on the apex of the structure, but reservoir quality and thickness may improve significantly on the flanks. Deeper objectives were found to be water-bearing.

North Dana

The North Dana discovery was made in late 1983 with the drilling and testing of North Dana I-43, located on the Outer Ridge, 100 km northeast of Hibernia. The well flowed gas at 361 606 m^3/d and 52.7° API condensate at 46.4 m^3/d from 10.4 m of net pay in sandstone facies of the Upper Jurassic (Kimmeridgian) Rankin Formation at 4536–4548 m below KB. The structure is a large, tilted fault block with Jurassic units unconformably overlain by thin bedded Upper Cretaceous limestone (Petrel Member).

Terra Nova

The Terra Nova oil field was discovered in mid-1984 with the drilling and testing of the Terra Nova K-08 wildcat, located on the southeast flank of the Jeanne d'Arc Basin, 39 km southeast of Hibernia. The well flowed oil on tests of three separate sandstone zones: 104 m^3/d of 32.4° API oil from a limited reservoir at the top of the Rankin Formation at 3530–3544 m; 616 m^3/d of 33.4° API oil from 41 m of net pay in the Jeanne d'Arc Formation at 3380–3423 m; and 174 m^3/d of 32.5° API oil from 4 m of net pay in another zone in the Jeanne d'Arc Formation at 3329–3336 m.

The Terra Nova structure is a north-plunging, possibly salt-cored anticlinal nose with a keystone graben at the crest. Closure is provided by the western graben-bounding fault, the north and east flanks of the plunging nose and the pinchout of the Jeanne d'Arc sandstone reservoir to the south. The northern closure is also provided by a large west-northwest trending fault. An oil/water contact in the main Jeanne d'Arc reservoir was encountered at 3415 m in the K-08 well. Subsequent drilling has demonstrated that this contact is restricted to a small block. An oil/water contact for the field has not been drilled but pressure data indicate one at about 3543 m. Eight follow-up wells (two wildcats, six delineation) have been drilled on the Terra Nova structure. Five of the delineation wells were successful in extending oil reserves in the main reservoir horizon, as follows: K-07, drilled in late 1985 in the graben, with 27.8 m of net oil pay; I-97, drilled in early 1986 on the east flank of the nose, with 7.8 m of net oil pay; H-99, drilled in late 1987, also on the east flank, with 37.2 m of net oil pay; E-79, drilled in mid-1988, also on the east flank, with 51 m of net oil pay in the main reservoir and 17.6 m in a shallower, laterally restricted reservoir; and C-09, drilled in early 1988 in the graben, with 53.4 m of net oil pay in the main reservoir and 7 m in the basal sandstone of the Jeanne d'Arc Formation. One of the follow-up wildcats, Beothuk M-05, located 5 km south of the K-08 discovery well in the graben and tested in early 1985, flowed oil from a separate reservoir in the Jeanne d'Arc, which was not connected with the main field and had limited areal extent. The K-17 wildcat and the K-18 delineation well, both drilled on the west flank of the plunging nose outside of the graben, found the Jeanne d'Arc sandstone zones to be water-bearing.

Trave

The Trave discovery was made in mid-1984 with the drilling and testing of the Trave E-87 well, located on the western margin of the Outer Ridge, 65 km east-northeast of Hibernia. The well flowed gas at rates of up to 506 871 m^3/d on tests of 8.8 m of net pay in the Hibernia Formation between 2144 and 2248 m with 69.3° API condensate at 82.8 m^3/d.

The structure is an east-dipping, tilted fault block, with an updip seal provided by the subcrop of Hibernia sandstone below shale of the Tertiary Banquereau Formation.

South Mara

The South Mara discovery was made in late 1984 with the drilling and testing of the South Mara C-13 wildcat, located in the Jeanne d'Arc Basin, 16 km east-southeast of Hibernia. The well flowed 34.7° API oil at 276 m^3/d from 6.2 m of net oil pay in the Lower Cretaceous Avalon/Ben Nevis Formation at 2952–2958 m. Gas at 399 267 m^3/d and 58.7° API condensate at 105 m^3/d flowed on test of the overlying gas cap at 2926–2932 m (27.4 m of net gas pay).

The structure is an elongated, northeast-dipping fault block, bounded to the southwest by an antithetic fault of the Trans-Basin Trend.

Whiterose

The Whiterose field was discovered in late 1984 with the drilling and testing of the Whiterose N-22 well, located near the east flank of the Jeanne d'Arc Basin, 52 km east of Hibernia. The well flowed 32° API oil from 7.6 m of net sandstone pay in the Hibernia Formation at 3542–3572 m at rates of up to 87 m^3/d. A test of the Eastern Shoals Formation (1.5 m of net pay) at 2725–2727 m flowed gas at 40 125 m^3/d, whereas tests of the overlying Avalon/Ben Nevis reservoir at 2663–2695 m, the main reservoir in the well with 34.8 m of net sandstone pay, flowed at up to 604 734 m^3/d gas and 107 m^3/d 56.3° API condensate.

The structure is a very large, probably salt-cored, faulted dome. The main periods of uplift were at the end of the Jurassic, and in Aptian to Albian times. Isochronal evidence indicates salt movement during both the Early and Late Cretaceous over the main domal part of Whiterose.

Four delineation wells have been drilled on the structure. The first of these, J-49, drilled in late 1985 on the southwest flank of the dome, encountered distal nonreservoir facies in the Hibernia Formation, but tested oil and gas from the Avalon/Ben Nevis objective, which had 22.6 m of net oil pay and 5.8 m of net gas pay. Gas was also tested from 4.5 m of net pay below the oil accumulation. The second delineation well, L-61, drilled on the west flank and tested in late 1986, was not drilled deeply enough for the Hibernia Formation to be evaluated. The Avalon/Ben Nevis reservoir was tight, but tested gas from 5 m of net pay in a Paleocene sandstone (the South Mara unit of the Banquereau Formation). The third delineation well, E-09, drilled in late 1987 to mid-1988 in the south flank "saddle" area, flowed oil from 87.8 m of net oil pay underlying a gas column with 12.8 m of net gas pay in the Ben Nevis Formation. The fourth delineation well, A-90, was dry and abandoned due to lack of reservoir facies. It defined the eastern limit of the field.

West Ben Nevis

The West Ben Nevis discovery was made in mid-1985 with the drilling and testing of West Ben Nevis B-75, located in the Jeanne d'Arc Basin, 32 km southeast of Hibernia. The well flowed oil on tests of three separate sandstone zones as follows: 380 m^3/d of 34.1° API oil from 12.8 m of net pay in the Jeanne d'Arc Formation at 4498–4507 m; 235 m^3/d of 22.8° API oil from 14.6 m of net pay in the Eastern Shoals Formation at 2445–2465 m; and 97 m^3/d of 28.1° API oil from 4.2 m of net pay in the Ben Nevis Formation at 2002–2015 m.

The structure is a tilted fault block, part of the Trans-Basin Fault Trend, between the Ben Nevis and Hebron fault structures.

Mara

The Mara discovery was made in early 1985 with the drilling and testing of Mara M-54, located in the Jeanne d'Arc Basin, 7 km southeast of Hibernia. The well flowed oil from two sandstone zones: 122 m^3/d of 20.5° API oil from a sandstone lens in the lower part of the Dawson Canyon Formation at 2403–2409 m; and 99 m^3/d of 21.6° API oil from 5 m of net pay within a Paleocene fan sequence (South Mara unit) of the Banquereau Formation at 1852–1857 m.

The Upper Cretaceous oil accumulation is considered to be limited in area. The Paleocene find, on the other hand, could be quite extensive, and has opened up an entirely new and promising exploration play — shale-enclosed stratigraphic sandstone bodies within the lower Tertiary section. The fan deposit in the discovery well appears to have had its source to the west. It was fed by channels cutting into the Dawson Canyon Formation, and deposited at the foot of the Upper Cretaceous shelf.

North Ben Nevis

The North Ben Nevis field was discovered in late 1985 with the drilling and testing of North Ben Nevis P-93, located in the Jeanne d'Arc Basin, 20 km east-southeast of Hibernia. The well flowed 33.9° API oil at 447 m^3/d on two tests of the Avalon/Ben Nevis Formation sandstone at 3080–3095 m (19.4 m of net oil pay). A test of the gas cap (15.4 m of net gas pay) at 3062–3067 m flowed gas at 479 630 m^3/d and 51.8° API condensate at 87 m^3/d.

The structure is an elongate, northeast-dipping fault block, bounded to the southwest by an antithetic fault of the Trans-Basin Trend.

A delineation well, M-61, was drilled 5 km southeast of the discovery well in early 1986 and tested in mid-1987. The well flowed oil from an Avalon/Ben Nevis sandstone (17.2 m of net oil pay) at 874 m^3/d. A gas cap, with 16.2 m of net pay, was not tested.

Fortune

The Fortune discovery was made in mid-1986 with the drilling and testing of Fortune G-57, located 50 km east-southeast of Hibernia on the east flank of the Jeanne d'Arc Basin. The well flowed oil on tests of three sandstone zones as follows: 134 m^3/d of 34.8° API oil from a thin, fault-bounded sliver of the Jeanne d'Arc Formation at 4031–4040 m; 156 m^3/d of 36.2° API oil from 7.4 m of pay, in the lower Hibernia zone, at 3989–4003 m; and 678 m^3/d of 35.5° API oil and 151 189 m^3/d of gas from a thin bed of sandstone in the Rankin Formation at 4417–4429 m. Only the Hibernia Formation reservoir tested at 3989–4003 m appears from test analysis to have significant areal extent. The other zones tested are limited reservoirs.

The structure is a closure against a major down-to-the-basin fault, on the west flank of the Morgiana Uplift (Figs. 2, 26).

Springdale

The Springdale discovery was made in early 1989 with the drilling and testing of Springdale M-29, located 45 km southeast of Hibernia on the east flank of the Jeanne d'Arc Basin. Well data is confidential until May 14, 1991. However, Texaco Canada Resources has announced limited test results from two zones. The first zone flowed 14.4° API oil at a rate of 62 m^3/d from a depth of approximately 1500 m below KB. The second zone flowed gas at a rate of 331 000 m^3/d from a depth of approximately 1300 m below KB.

PETROLEUM GEOLOGY AND PLAYS

Fifteen hydrocarbon exploration plays in the Jeanne d'Arc Basin and environs (Fig. 13) are defined by area and type of trap, and by the lithostratigraphic horizon providing the reservoir facies.

A definition of each play, and a description of the lithology, environment of deposition, and reservoir quality of the target horizon are provided. Structural history, source rock maturity, and hydrocarbon migration and trapping are briefly addressed. These are followed by a review of drilling results for each play, and finally by a subjective summary of the hydrocarbon potential and risks of that play. Also included is a map showing the areal extent of each play and a schematic cross-section illustrating the trap type.

TRANS-BASIN FAULT TREND GROUP

The Trans-Basin Fault Trend is a zone of subparallel, normal faults trending northwest across the centre of Jeanne d'Arc Basin. These faults bound a series of generally elongate, tilted fault blocks (Figs. 14–23). The Trans-Basin Fault Trend Group contains five plays.

Jeanne d'Arc Formation

Play definition. The clastic rocks of the uppermost Jurassic Jeanne d'Arc Formation provide reservoirs in the structural traps defined by the Trans-Basin Fault Trend (Figs. 14, 15).

Geology. The Jeanne d'Arc Formation comprises alluvial to braided fluvial and deltaic conglomerate, sandstone, and shale. These unconformably overlie limestone of the Rankin Formation and are conformably overlain by the Fortune Bay Shale. In the southern end of the Jeanne d'Arc Basin, wide valleys were cut deeply into older sediments. The clastic rocks were deposited as a northward-thickening wedge of stacked channel sandstone, erratic conglomerate beds, and basinal shale with thin sandstone stringers.

The Jeanne d'Arc Formation is relatively deeply buried over much of the area of the Trans-Basin Fault Trend. Pervasive cementation of the clastics results in thin net pay (5–13 m), and porosity averaging 7 to 14 per cent.

Most movement on faults defining the Trans-Basin Fault Trend occurred during the Aptian–Albian. This period of faulting created hydrocarbon traps within the Jeanne d'Arc Formation, in horsts, upthrown against the Fortune Bay Shale, and in grabens, downfaulted against Rankin Formation limestone and shale (Fig. 15). The Fortune Bay Shale also provides an effective cap rock for the entire Jeanne d'Arc Formation, and shale interbeds commonly seal multiple reservoirs within the formation. The faults of the Trans-Basin Fault Trend provide potential vertical migration pathways for hydrocarbons generated in the underlying Egret Member, and juxtaposition of this source rock against the Jeanne d'Arc Formation locally provides lateral migration pathways. The Egret Member is mature over most of the Trans-Basin Fault Trend area and may be overmature in the deepest parts (Fig. 8).

Exploration history. Six structures of the Trans-Basin Fault Trend have been drilled in the Jeanne d'Arc Formation. In order of drilling these are: Hibernia, Hebron, Nautilus, South Mara, West Ben Nevis, and North Trinity. Oil was first tested from the Jeanne d'Arc Formation in 1979 from Hibernia P-15 (Fig. 13). In mid-1981, oil flowed from this formation in Hebron I-13. Oil was similarly recovered on drill stem testing in West Ben Nevis B-75 in mid-1985, though flow rates declined during testing, indicating a limited reservoir.

Summary. The generally deep burial, variable sand distribution, low net pays with low porosities in the area of the Trans-Basin Fault Trend result in a relatively low potential volume of entrapped hydrocarbons in the Jeanne d'Arc Formation. However, it is possible that local conditions may have resulted in moderate accumulations.

Hibernia Formation

Play definition. The clastic rocks of the lowest Cretaceous Hibernia Formation provide reservoirs in the structural traps defined by the Trans-Basin Fault Trend (Figs. 16, 17).

Geology. The Hibernia formation encompasses two progradational, fluvial-deltaic cycles: the lower zone and the upper zone.

The lower zone comprises clean, fine to coarse grained, carbonaceous, stacked fluvial channel sandstone interbedded with overbank splay siltstone, shale, and coal. The western margin is sandstone dominated, whereas the eastern is bay-fill shale dominated.

The upper zone, or Hebron Well Member, is characterized by thick, massive sandstone deposited under marine conditions. This upper zone progrades into the Jeanne d'Arc Basin from the south to the southeast and grades laterally to prodelta shale in the Hibernia structure area.

Reservoir quality is commonly excellent in the Hibernia Formation, with net pay sandstone ranging from 15 to 50 m thick and porosity averaging between 11 and 16 per cent. Both net porous sandstone and average porosity generally decrease as burial depths increase in the area of the Trans-Basin Fault Trend, as indicated by the low values in Ben Nevis I-45 and South Mara C-13. The average Hibernia Formation porosity found in the Hibernia structure (15.5%) is higher than in other structures buried to similar depths, possibly indicating a unique diagenetic or depositional history for this reservoir in the Hibernia field (Brown et al., 1989).

Most movement on faults defining the Trans-Basin Fault Trend occurred during the Aptian–Albian. This period of faulting created structural traps. The Hibernia Formation, in horsts, is upthrown against Whiterose Shale and, in grabens, downfaulted against Fortune Bay Shale (Fig. 17). Prodelta shale and "B" Marker limestone provide overlying seals for hydrocarbon traps. The stacking of thick, clastic sequences of the upper and lower zones in the southeast end of the Trans-Basin Fault Trend increases the risk of leakage across faults in that area. The faults of the Trans-Basin Fault Trend provide potential vertical migration

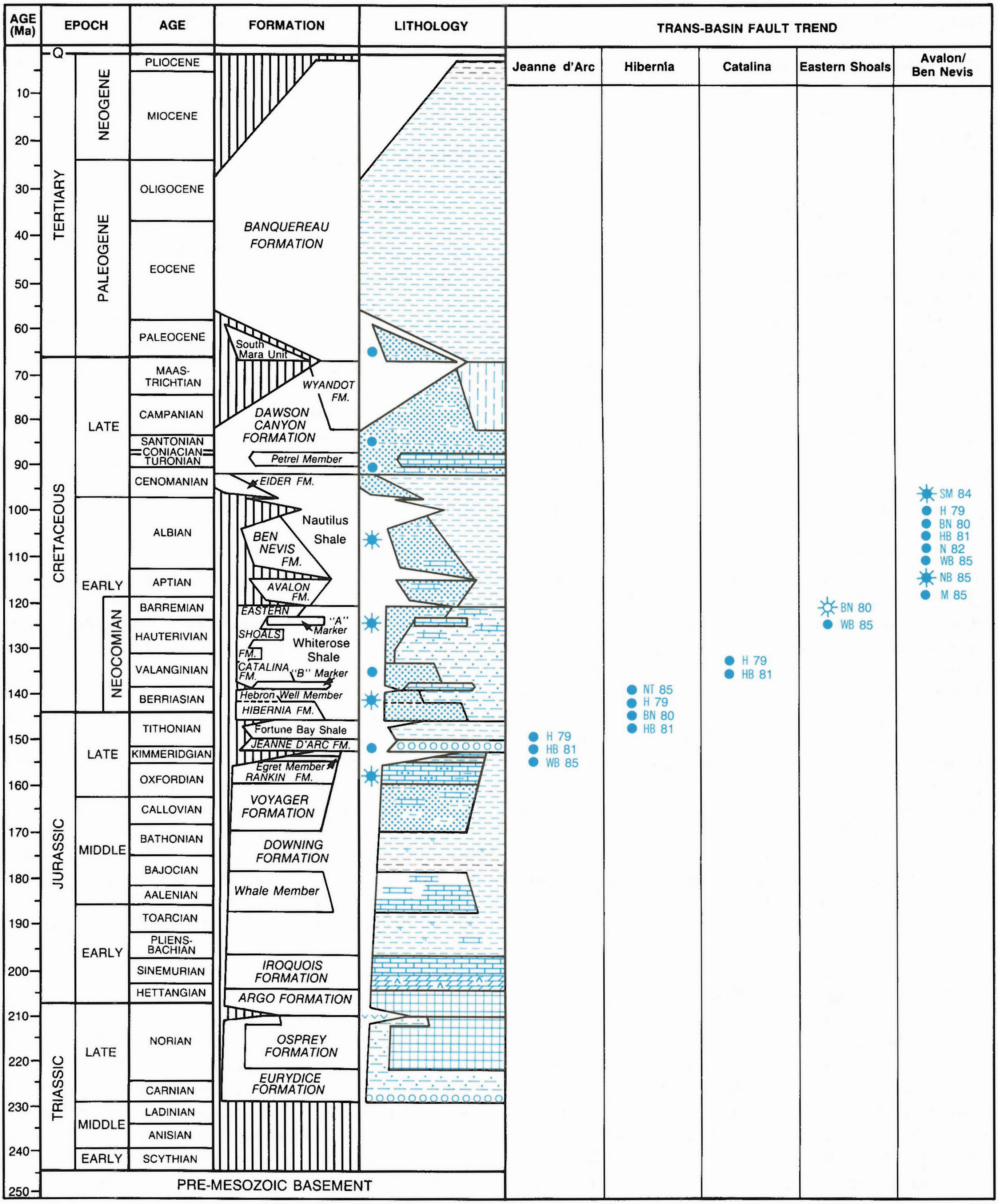
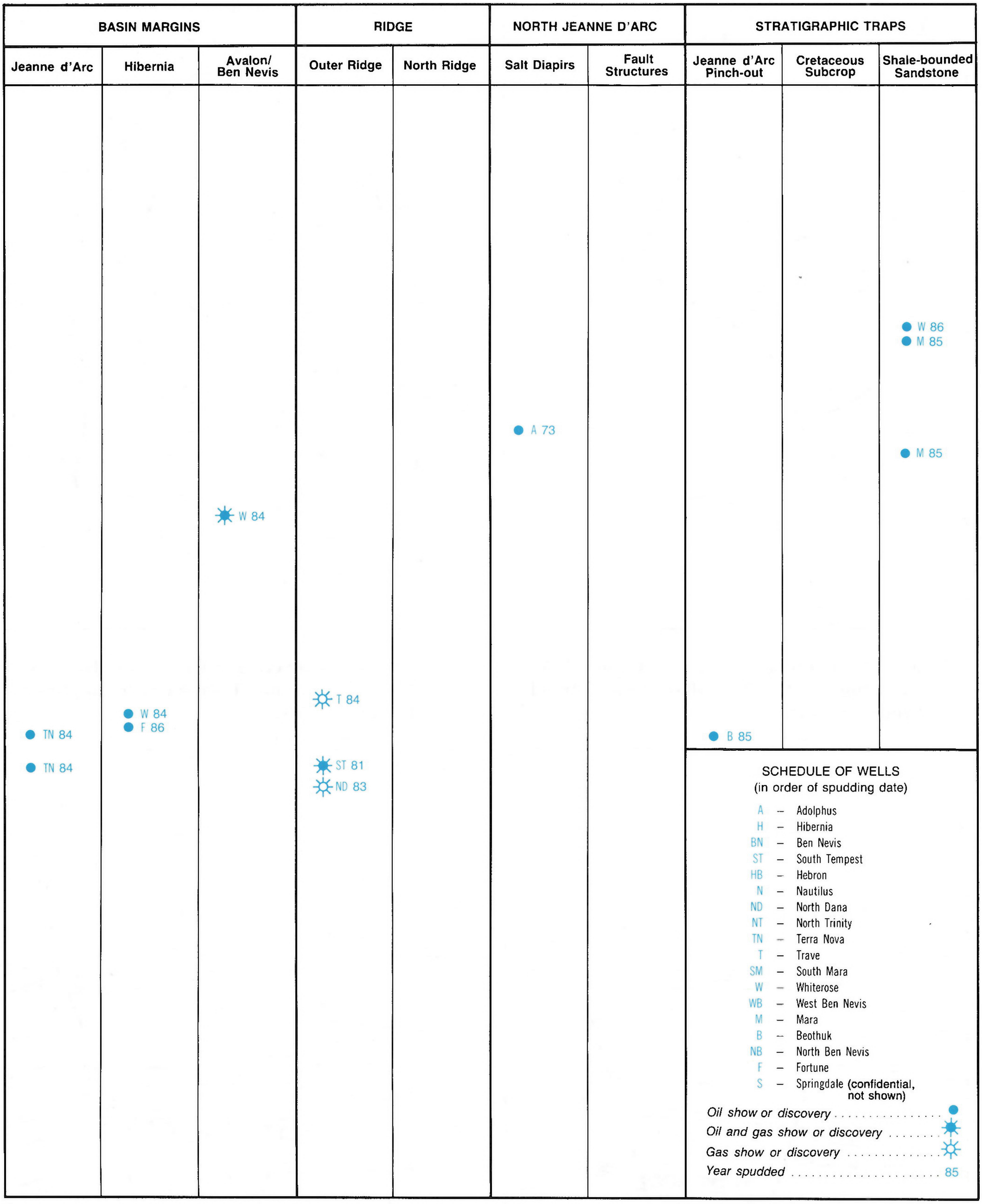


Figure 13. Classification of plays, record of discoveries and shows of oil and gas related to the stratigraphy. See Figure 4 for legend of lithotypes.



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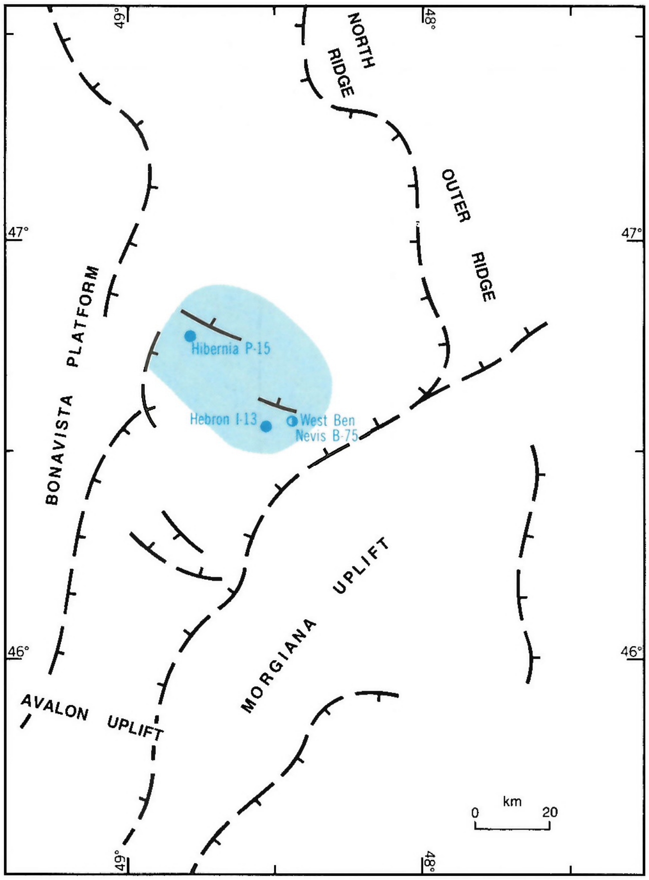

Figure 14. Objective area of the Jeanne d'Arc Formation in the Trans-Basin Fault Trend Group of plays.

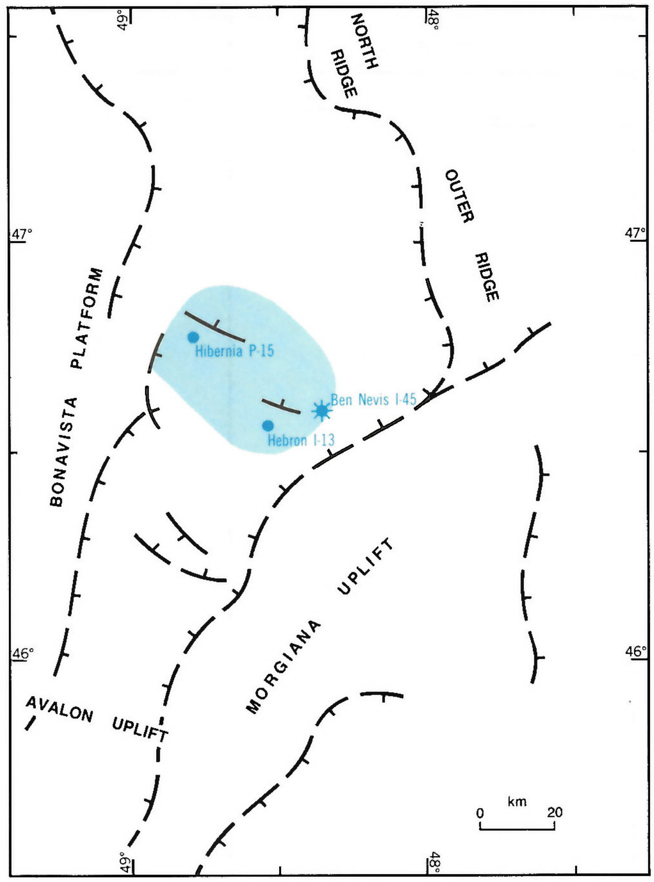

Figure 16. Objective area of the Hibernia Formation in the Trans-Basin Fault Trend Group of plays.

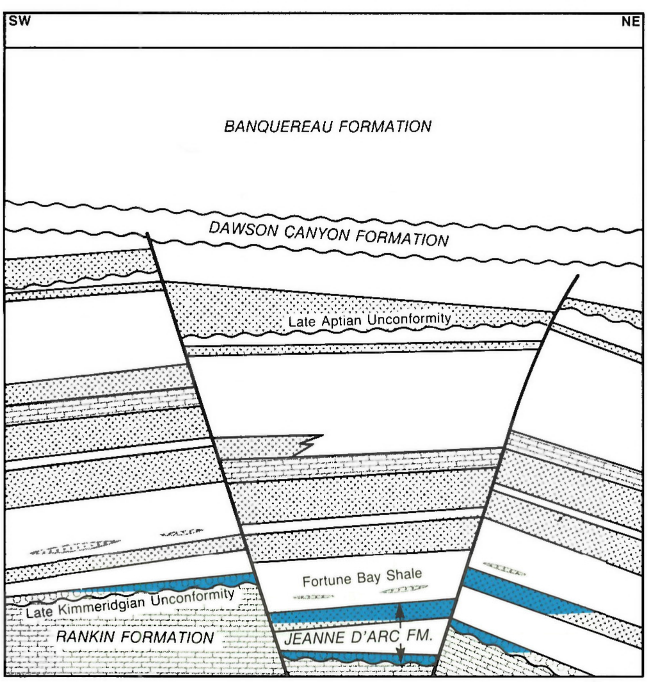

Figure 15. Schematic cross-section illustrating the trap type of the Jeanne d'Arc Formation in the Trans-Basin Fault Trend Group of plays.

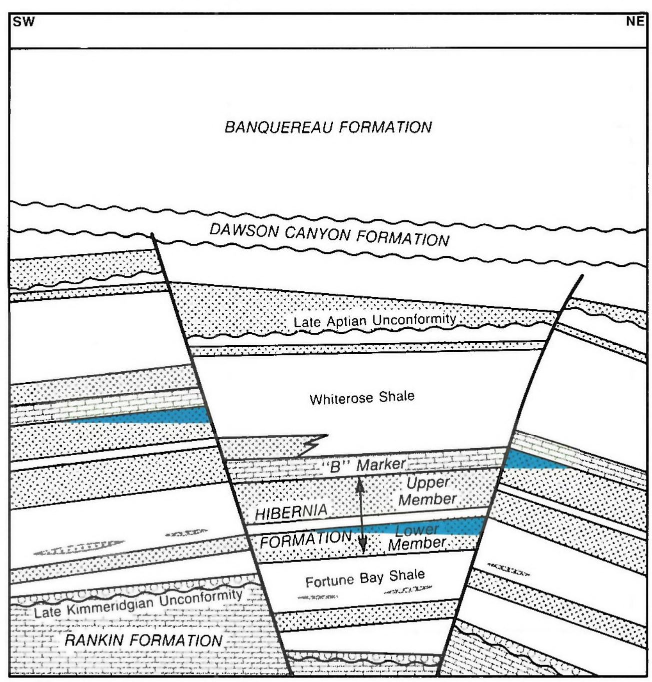

Figure 17. Schematic cross-section illustrating the trap type of the Hibernia Formation in the Trans-Basin Fault Trend Group area.

pathways to the Hibernia Formation for hydrocarbons generated in the Egret Member. The Egret Member is mature over most of the Trans-Basin Fault Trend and may be overmature in the deepest parts of the Trend. This may account for the light gravity of hydrocarbons encountered in Ben Nevis I-45.

Exploration history. Nine structures of the Trans-Basin Fault Trend have been drilled in the Hibernia Formation. In order of drilling these are: Hibernia, Ben Nevis, Hebron, Nautilus, South Mara, West Ben Nevis, Mara, North Ben Nevis, and North Trinity. In 1979, oil was discovered in the lower zone of the Hibernia Formation in the Hibernia structure by drilling the Hibernia P-15 well (Fig. 13). Condensate or light oil (39° API) was flow-tested from the Hibernia formation (lower zone) in Ben Nevis I-45 in mid-1980. In mid-1981, Hebron I-13 tested oil from the upper zone of the Hibernia Formation.

Summary. The widespread distribution of the Hibernia Formation and the common occurrence of thick, high quality reservoir strata make this a highly prospective target.

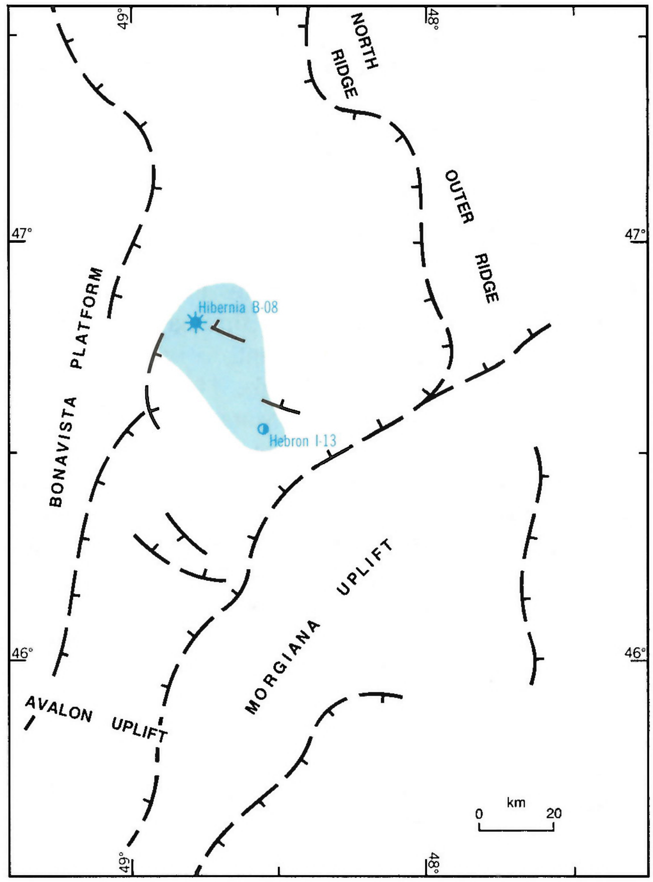

Figure 18. Objective area of the Catalina Formation in the Trans-Basin Fault Trend Group of plays.

Catalina Formation

Play definition. The clastic rocks of the Lower Cretaceous Catalina Formation locally provide reservoirs in the structural traps defined by the Trans-Basin Fault Trend (Figs. 18, 19).

Geology. The Catalina Formation comprises thin sandstone, siltstone, shale, and sandy, oolitic limestone. The sandstone is generally very fine grained, shaly, calcite-cemented, and bioturbated. These sediments likely represent a minor influx of clastic material into a marine shelf environment. The Catalina Formation grades laterally into the Whiterose Shale in the area of the West Ben Nevis B-75 well.

Net pay varies from 1 to 24 m, with average porosity ranging from 10 to 17 per cent. Reservoir quality is extremely variable over short distances, as seen in the Hibernia structure wells.

Most movement on faults defining the Trans-Basin Fault Trend occurred during the Aptian–Albian. This period of faulting created structural traps. In horsts, the Catalina Formation is upthrown against the Whiterose Shale (Fig. 19). In grabens, the Catalina Formation is commonly juxtaposed with the Hibernia Formation and, as a result, lacks a lateral seal (Fig. 19). The Whiterose Shale provides a vertical seal. The faults of the Trans-Basin Fault Trend provide potential vertical migration pathways to the Catalina Formation for

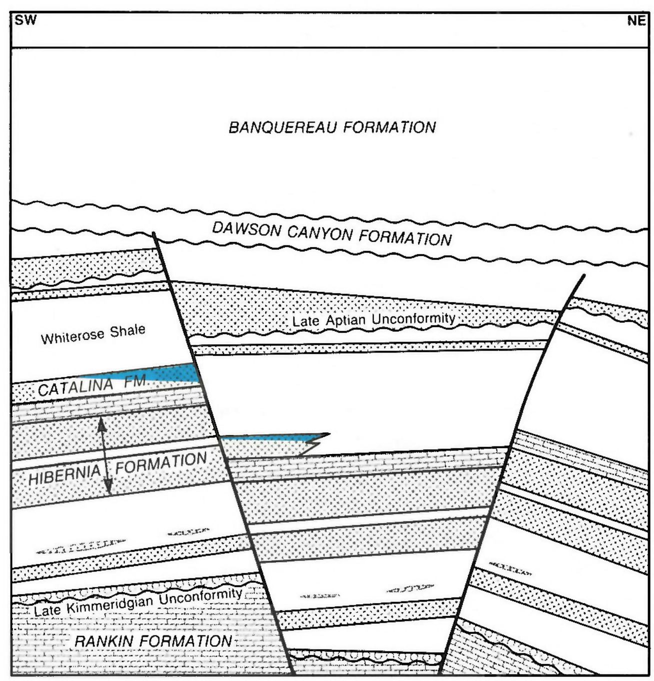

Figure 19. Schematic cross-section illustrating the trap type in the Catalina Formation of the Trans-Basin Fault Trend Group.

hydrocarbons generated in the older Egret Member. The Egret Member is mature over most of the Trans-Basin Fault Trend area and may be overmature in the deepest portion of the Trend. The oil recovered from the Catalina Formation in Hebron I-13 was heavy (16.9° API), but geochemical analysis suggests that it is not severely biodegraded.

Exploration history. Nine structures in the Trans-Basin Fault Trend have been drilled through the Catalina Formation or its lateral equivalent. In order of drilling these are: Hibernia, Ben Nevis, Hebron, Nautilus, South Mara, West Ben Nevis, Mara, North Ben Nevis, and North Trinity. However, the Catalina Formation was not present in Ben Nevis I-45, West Ben Nevis B-75, or North Ben Nevis P-93 due to lateral gradation to the Whiterose Shale. Oil has been tested from three wells on the Hibernia structure: B-08 in late 1980, K-18 in late 1981, and B-27 in late 1983 (Fig. 13). Heavy oil (1.6 m^3) was reverse circulated from a drill stem test over the Catalina Formation in Hebron I-13 in mid-1981.

Summary. The Catalina may be a minor, secondary target due to poor reservoir development.

Eastern Shoals Formation

Play definition. Clastic rocks of the Lower Cretaceous Eastern Shoals Formation provide reservoirs in the structural traps along the southeastern end of the Trans-Basin Fault Trend (Figs. 20, 21).

Geology. The Eastern Shoals Formation prograded into the southern and southeastern Jeanne d'Arc Basin, where it comprises very fine to coarse grained, massive sandstone with abundant calcareous cement, grading to sandy, oolitic limestone. To the northwest and northeast, the Eastern Shoals grades to thin limestone and shale. This unit was likely deposited in a shallow water marine environment, which received clastic input from the rejuvenated Avalon Uplift.

The Eastern Shoals Formation is about 100 m thick over much of the southeastern end of the Trans-Basin Fault Trend, but porous sandstone occurs only sporadically. Net pay ranges from 4 to 15 m in thickness. Average porosity is about 20 per cent, although it can range as low as 11 per cent in the more deeply buried parts of Trans-Basin Fault Trend.

Most movement on faults defining the Trans-Basin Fault Trend occurred during the Aptian–Albian. This created structural traps with the Eastern Shoals Formation, in horsts, upthrown against Nautilus Shale or the Avalon/Ben Nevis clastic rocks, and in grabens, down-

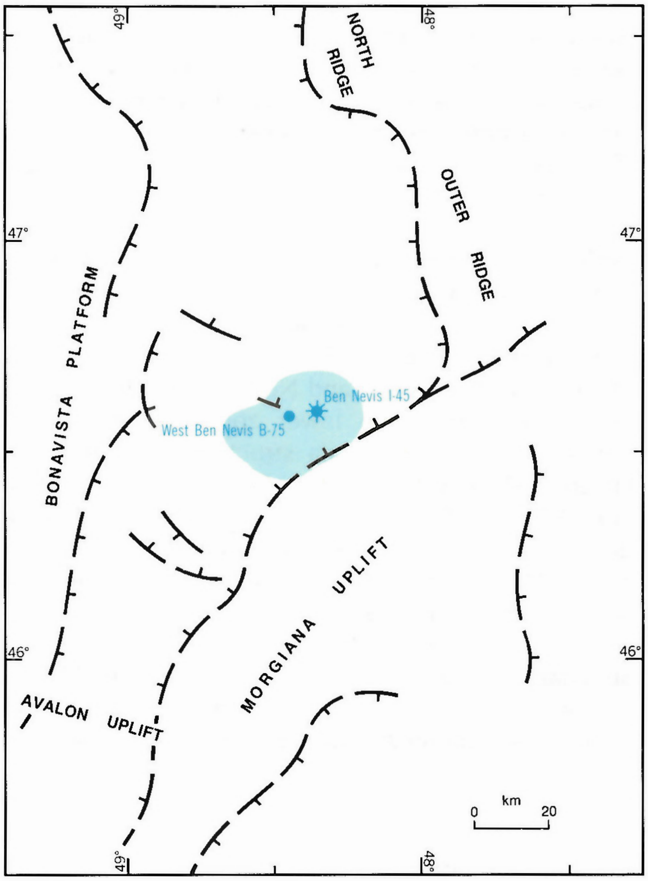

Figure 20. Objective area of the Eastern Shoals Formation in the Trans-Basin Fault Trend Group of plays.

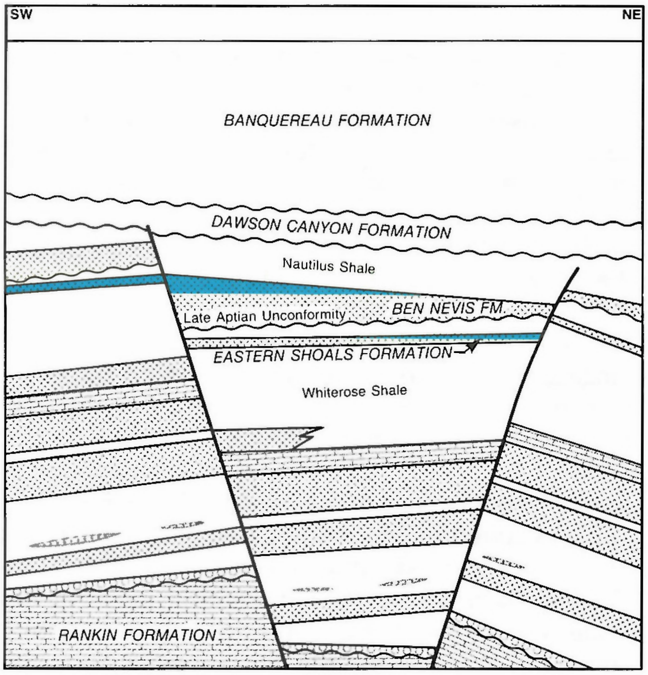

Figure 21. Schematic cross-section illustrating the trap type in the Eastern Shoals Formation in the Trans-Basin Fault Trend Group of plays.

faulted against Whiterose Shale (Fig. 21). Where the Eastern Shoals is juxtaposed with the Avalon/Ben Nevis reservoir, a common hydrocarbon trap may form. Shale is commonly found on top of the Eastern Shoals Formation, as in Ben Nevis I-45, where it provides a vertical seal. In other areas, however, these shales have been eroded and the seal is breached, as in Hebron I-13 and North Trinity H-71. The faults of the Trans-Basin Fault Trend provide potential vertical migration pathways for hydrocarbons generated in the Egret Member. The Egret Member is mature over most of the Trans-Basin Fault Trend area and may be overmature in the deepest parts of the Trend. The great depth of burial of the source rock in the Ben Nevis structure may have resulted in overmaturity in this area, possibly accounting for the gas and condensate that was encountered in the Eastern Shoals Formation in Ben Nevis I-45.

Exploration history. Only five of the nine structures drilled on the Trans-Basin Fault Trend have encountered the Eastern Shoals Formation. The other four penetrated laterally equivalent limestone and shale. The five structures, in order of drilling, are: Ben Nevis, Hebron, West Ben Nevis, North Ben Nevis, and North Trinity. Hydrocarbons, in the form of gas and condensate, were first recovered in mid-1980 from the Eastern Shoals Formation in Ben Nevis I-45 (Fig. 13). In mid-1985, the West Ben Nevis B-75 well flowed 22.8° API oil from the Eastern Shoals.

Summary. The Eastern Shoals Formation is a local secondary target on the Trans-Basin Fault Trend due to the limited areal extent and amount of reservoir quality rock found in this unit.

Avalon/Ben Nevis formations

Play definition. Lower Cretaceous clastic rocks of the Avalon/Ben Nevis formations provide reservoirs in the structural traps defined by the Trans-Basin Fault Trend (Figs. 22, 23).

Geology. Coarsening-upward sandstone of the Avalon Formation prograded northward into the Jeanne d'Arc Basin in response to the rising Avalon Uplift. Fine to coarse grained, variably calcite-cemented sandstone was deposited mainly in the marine shoreface environment. The strata are locally preserved as a northward-thickening wedge below the erosional Late Aptian Unconformity. The Ben Nevis is a generally fining-upward sequence representing marine transgression. Clastic rocks range from porous, coarse grained, coaly sandstone to fine grained, commonly

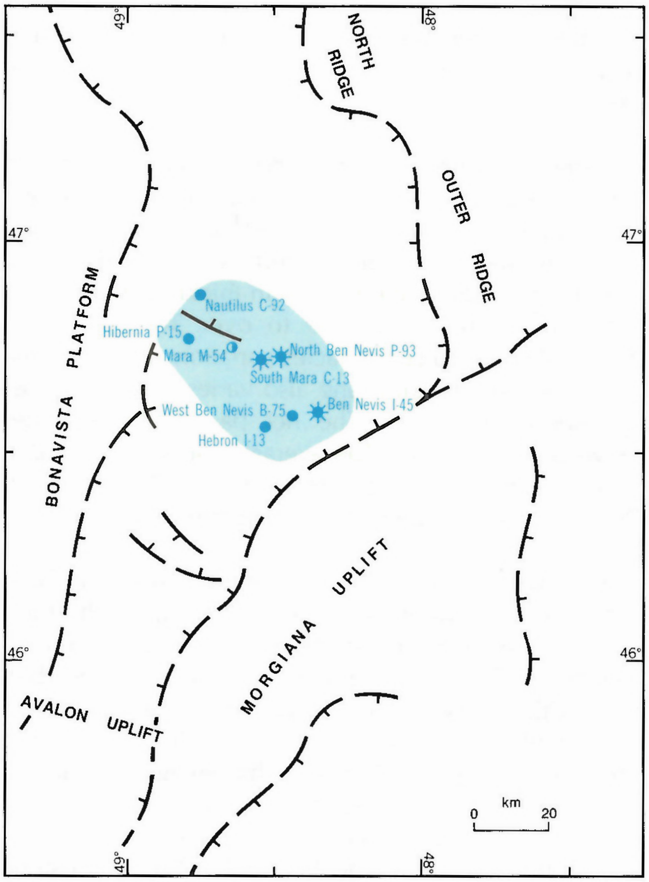

Figure 22. Objective area of the Avalon/Ben Nevis formations in the Trans-Basin Fault Trend Group of plays.

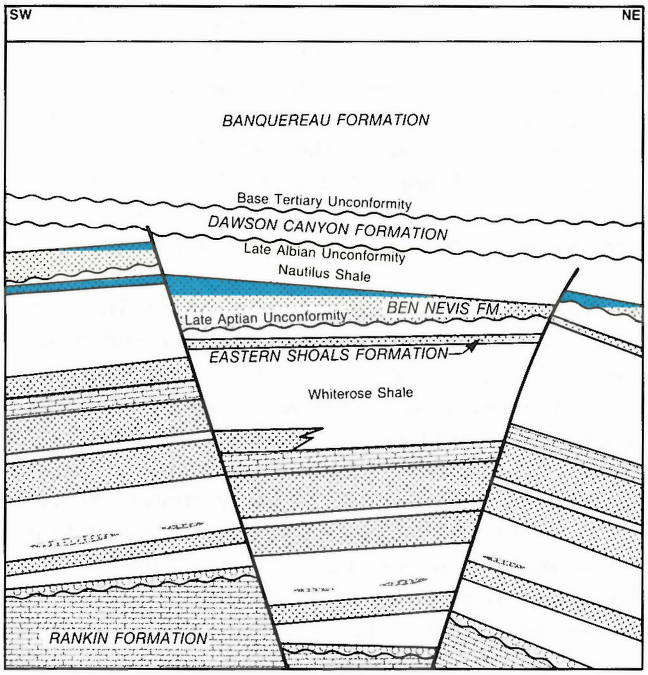

Figure 23. Schematic cross-section illustrating the trap type of the Avalon/Ben Nevis formations in the Trans-Basin Fault Trend Group.

calcite-cemented sandstone. These likely represent fluvial and estuarine to marine environments of deposition.

Variable thicknesses of preserved Avalon Formation sandstone are commonly overlain by porous sandstone of the Ben Nevis Formation, resulting in hydrodynamic communication between the formations. Sandstone of the Ben Nevis Formation varies in thickness from about 50 m in South Mara C-13 to over 300 m in Ben Nevis I-45, due to lateral facies variation. The thickness of the Ben Nevis sandstone also varies abruptly across syndepositional faults. The net pay thickness varies between 4 and 36 m. The average porosity of the Ben Nevis sandstone ranges from 16 to 25 per cent. Reservoir quality generally deteriorates upward.

Most movement on faults defining the Trans-Basin Fault Trend occurred during the Aptian–Albian, synchronous with deposition of the Ben Nevis and Nautilus formations. This period of faulting created hydrocarbon traps with the Avalon/Ben Nevis sandstone, in grabens, down-faulted against Whiterose Shale and Eastern Shoals clastics and, in horsts, upthrown against Nautilus Shale (Fig. 23). Where the Avalon/Ben Nevis is juxtaposed with the Eastern Shoals, a common hydrocarbon trap may form. The Avalon/Ben Nevis sandstone is commonly incompletely offset across faults, resulting in a lack of lateral seal. The Nautilus Shale provides effective vertical seals for the Avalon/Ben Nevis traps. The faults of the Trans-Basin Fault Trend provide potential vertical migration pathways for hydrocarbons generated in the Egret Member. The Egret Member is mature over most of the Trans-Basin Fault Trend area and may be overmature in the deepest parts. This may explain the gas columns encountered in the Ben Nevis Formation in the South Mara and North Ben Nevis structures. In contrast, heavy oil (16.9–19° API) was encountered in the Hebron structure, but geochemical analysis suggests that it is not severely biodegraded.

Exploration history. Nine structures on the Trans-Basin Fault Trend have been drilled in the Avalon/Ben Nevis formations. Seven of these structures were found to contain hydrocarbons, one was water-bearing (North Trinity H-71) and one had minor oil shows (Mara M-54). Oil first flowed from this reservoir in Hibernia P-15 in late 1979 (Fig. 13). Minor amounts of heavy oil (20.3 to 24.8° API) were recovered on drill stem testing of low quality reservoir rock at the top of the Ben Nevis Formation in Ben Nevis I-45 in mid-1980. Heavy oil flowed from high quality reservoir rocks of the Ben Nevis Formation in Hebron I-13 in mid-1981. A thin conglomeratic unit in the Avalon/Ben Nevis reservoir flowed high rates of oil on drill stem testing of Nautilus C-92 in mid-1982. Oil and gas flowed from high quality reservoir rocks of the Avalon/Ben Nevis reservoir in South Mara C-13 in late 1984 and in North Ben Nevis P-93 in late 1985. Oil was recovered from a thin hydrocarbon column at the top of the Avalon/Ben Nevis reservoir in West Ben Nevis B-75 in mid-1985.

Summary. The Avalon/Ben Nevis reservoir in the Trans-Basin Fault Trend has the highest success ratio of any play in the Jeanne d'Arc Basin. Large volumes of hydrocarbons were discovered in the Hibernia and Hebron structures and there remains good hydrocarbon-trapping potential elsewhere.

BASIN MARGINS GROUP

The basin margins of the Jeanne d'Arc Basin are, for the purposes of this resource evaluation, considered to be the area defined by normal faults that separate the basin from the Bonavista Platform on the west and the Morgiana High and Outer Ridge on the east (Figs. 24–29). The faulting has created a series of tilted fault blocks with some structures rolled over into basin-bounding faults. Three plays are included in this group.

Jeanne d'Arc Formation

Play definition. The clastic rocks of the uppermost Jurassic Jeanne d'Arc Formation provide reservoirs in the structural traps found in this play area (Figs. 24, 25).

Geology. The Jeanne d'Arc Formation comprises alluvial to braided fluvial and deltaic conglomerate, sandstone, and shale. The stratigraphic setting in the area of the Basin Margins Group is the same as in the Trans-Basin Fault Trend Group area. The sandstone and conglomerate become less common to the north as the Jeanne d'Arc Formation grades laterally into the Fortune Bay Shale.

Net pays encountered in the one discovery (i.e., Terra Nova) to date have been variable, ranging from about 8 to over 50 m. This reflects, in part, the variability in sediment facies characteristics in this formation. Average porosity ranges between 15 and 22 per cent, the higher porosity values usually occurring in the shallower structures, such as Voyager.

Many of the basin-bounding faults were active during deposition of the Jeanne d'Arc Formation, resulting in thickening into, and thickness changes across, faults (Fig. 25). These faults were reactivated in Aptian–Albian

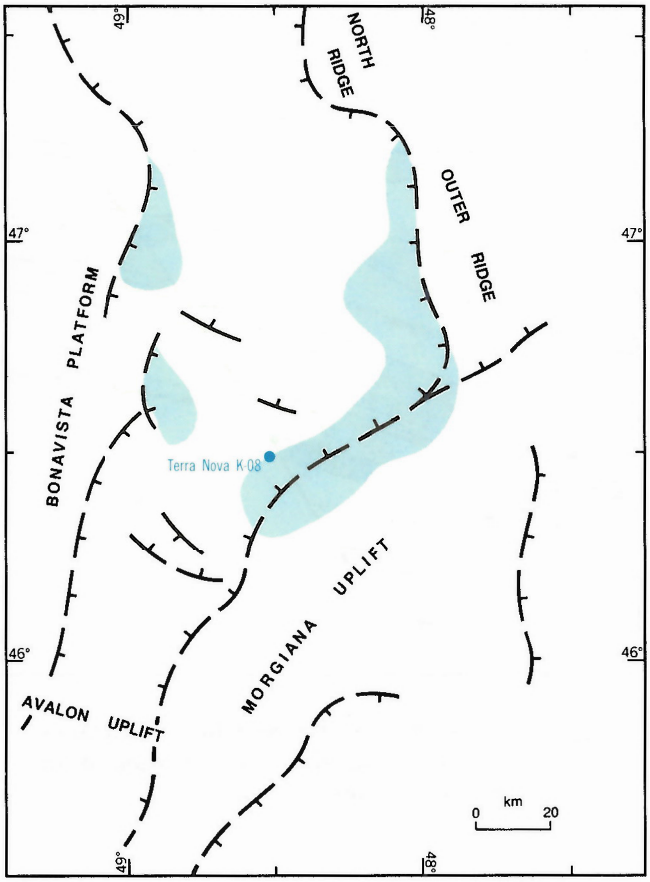

Figure 24. Objective areas of the Jeanne d'Arc Formation in the Basin Margins Group of plays.

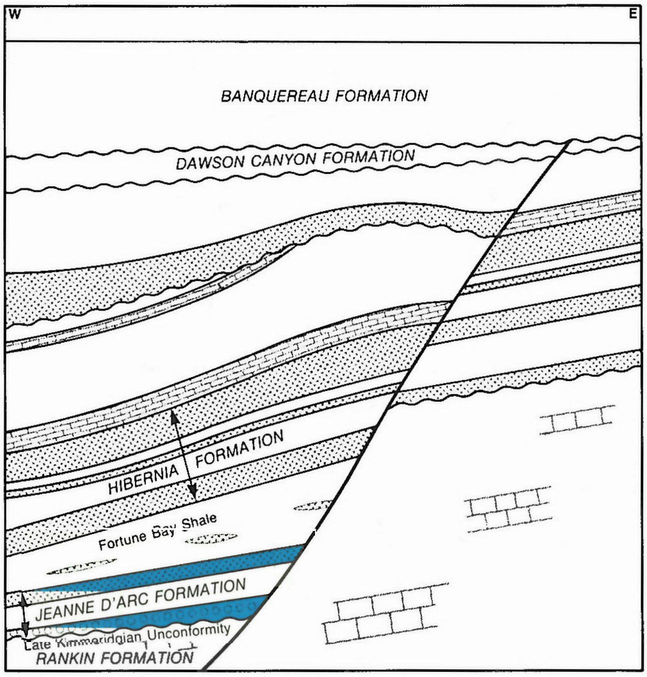

Figure 25. Schematic cross-section illustrating the trap type of the Jeanne d'Arc Formation in the Basin Margins Group of plays.

time, when the structural traps of this play were created. In grabens, the Jeanne d'Arc Formation is downthrown against shale and shaly limestone of the Rankin Formation (Fig. 25), whereas in horst blocks it is displaced against the Fortune Bay Shale and the Hibernia Formation. The Fortune Bay Shale provides an effective cap rock for the entire Jeanne d'Arc Formation, and shale interbeds may seal multiple reservoirs within the formation. The faults defining this play provide potential vertical migration pathways for hydrocarbons generated in the underlying Egret Member, whereas juxtaposition of this source rock with the Jeanne d'Arc Formation provides lateral migration pathways. The Egret Member is marginally mature to immature in shallower areas of the Basin Margins play, such as along the western edge of the Morgiana High. For structures in such areas to be hydrocarbon-bearing, lateral migration is required from adjacent areas where the source rocks are more deeply buried and more mature.

Exploration history. The Jeanne d'Arc Formation or its lateral equivalent has been encountered in six structures on the basin margins. In two of these, Archer and Whiterose, the Jeanne d'Arc Formation sandstone is absent, likely due to distance from the clastic source area. The remaining four structures were drilled in the following order: Egret, Rankin, Terra Nova and Voyager. Oil was first tested from the Jeanne d'Arc Formation on the basin margins from Petro-Canada et al. Terra Nova K-08 in mid-1984 (Fig. 13).

Summary. Reservoir quality in the Jeanne d'Arc Formation is highly variable over the area of the basin margins. This factor, in combination with others such as variable source rock maturity, results in a relatively high risk, but high potential play.

Hibernia Formation

Play definition. The clastic rocks of the lowest Cretaceous Hibernia Formation provide reservoirs in the structural traps found in this play area (Figs. 26, 27).

Geology. The Hibernia Formation encompasses two progradational, fluviodeltaic cycles: the lower zone and the upper zone (Hebron Well Member).

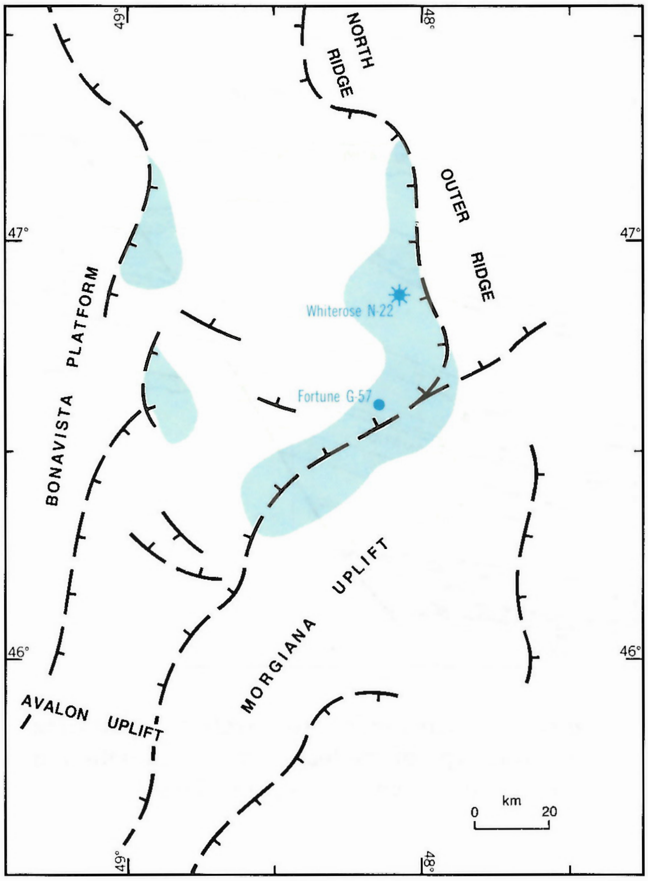

Figure 26. Objective areas of the Hibernia Formation in the Basin Margins Group of plays.

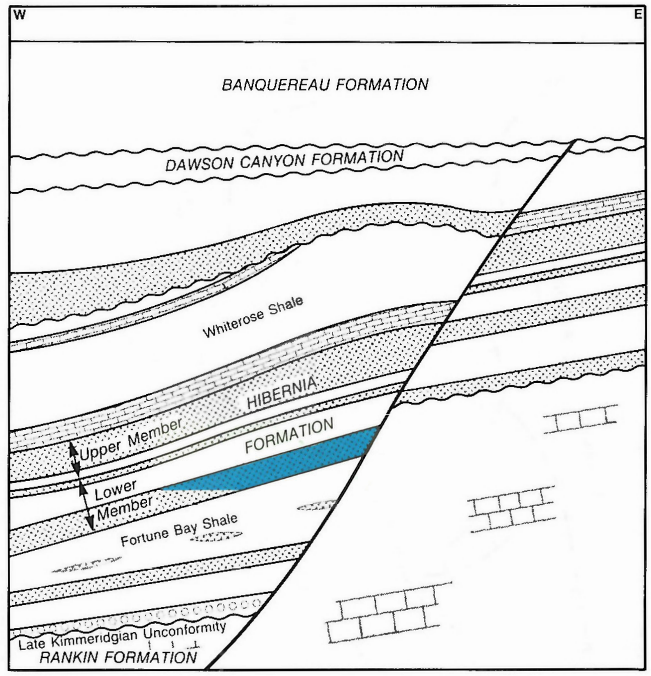

Figure 27. Schematic cross-section illustrating the trap type of the Hibernia Formation in the Basin Margins Group of plays.

The stratigraphic setting and environment of deposition of the Hibernia Formation in the objective area are identical with the settings in the Trans-Basin Fault Trend Group.

Reservoir quality varies, average porosity ranging from 12 to 26 per cent (average porosity decreases with increasing burial depth). The net pays encountered to date, however, have been thin (7 to 14 m).

Many of the north-south-trending, basin-bounding faults were active during deposition of the Hibernia Formation, resulting in thickening of this sequence into faults and thickness changes across faults (Fig. 27). These faults were reactivated in Aptian–Albian time, when the structural traps of this play were created. The Hibernia Formation, in grabens, may be downthrown against shale of the Fortune Bay or shale and argillaceous limestone of the Rankin Formation and, in horst blocks, may be upthrown against Whiterose Shale (Fig. 27). Prodelta shale and "B" Marker limestone provide overlying seals for hydrocarbon traps. The stacking of thick clastic sequences of the upper and lower zones increases the risk of leakage from the upper zone across faults along the eastern margin of the basin. The faults defining this play provide potential vertical migration pathways for hydrocarbons generated in the underlying Egret Member. The Egret Member is marginally mature to immature in shallower areas of the Basin Margins play, such as along the western edge of the Morgiana High. For structures in such areas to be hydrocarbon-bearing, lateral migration is required from adjacent areas where the source rocks are more deeply buried and more mature.

Exploration history. Seven structures on the basin margins have been drilled in the Hibernia Formation. In order of drilling these are: Egret, Rankin, Terra Nova, Voyager, Archer, Whiterose, and Bonne Bay. Oil was recovered from the Hibernia Formation in the basin margin structural area in Whiterose N-22 in late 1984 (Fig. 13). In mid-1986, oil was recovered from Fortune G-57.

Summary. High quality reservoir sandstone may combine with sufficient fault throw to give lateral seal, locally creating large hydrocarbon traps in this play.

Avalon/Ben Nevis formations

Play definition. Lower Cretaceous clastic rocks of the Avalon and Ben Nevis formations provide reservoirs in the structural traps defined by this trend (Figs. 28, 29).

Geology. The Avalon and Ben Nevis formations occupy the same stratigraphic position in the Basin Margins Group as in the Trans-Basin Fault Trend Group area. The environments of deposition in the two areas are the same.

Variable thicknesses of preserved Avalon Formation sandstone are directly overlain by porous sandstone of the Ben Nevis Formation, resulting in hydrodynamic communication between the formations. Sandstone of the Ben Nevis Formation varies greatly in thickness, from about 40 m in West Flying Foam L-23 to over 2500 m in Mercury K-76, due to lateral facies variation and growth into syndepositional faults. Net pay sandstone in the Whiterose field varies between 30 and 100 m in thickness. Average porosity of the Avalon/Ben Nevis sandstone ranges between 12 and 17 per cent. Reservoir quality generally deteriorates upward. This situation corresponds to the decrease in grain size and bed thickness and increase in argillaceous content associated with the transgression represented by the Ben Nevis Formation.

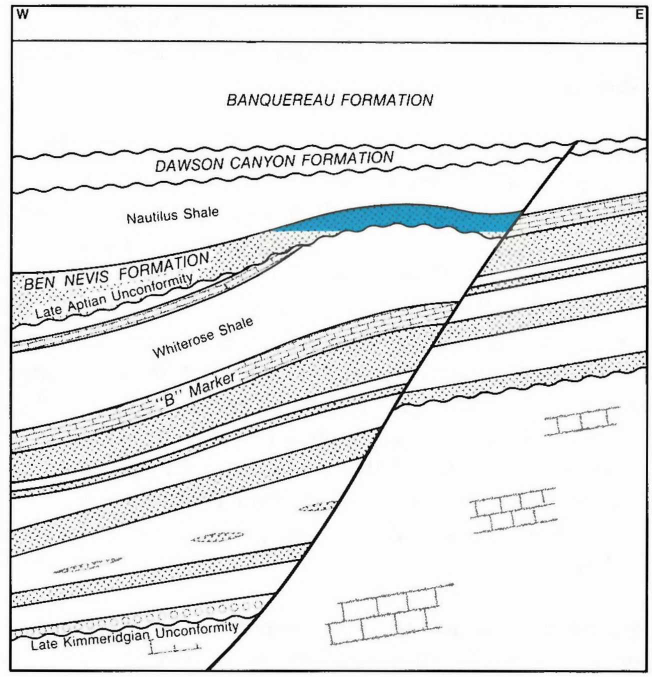

Figure 29. Schematic cross-section illustrating the trap type of the Avalon/Ben Nevis formations in the Basin Margins Group of plays.

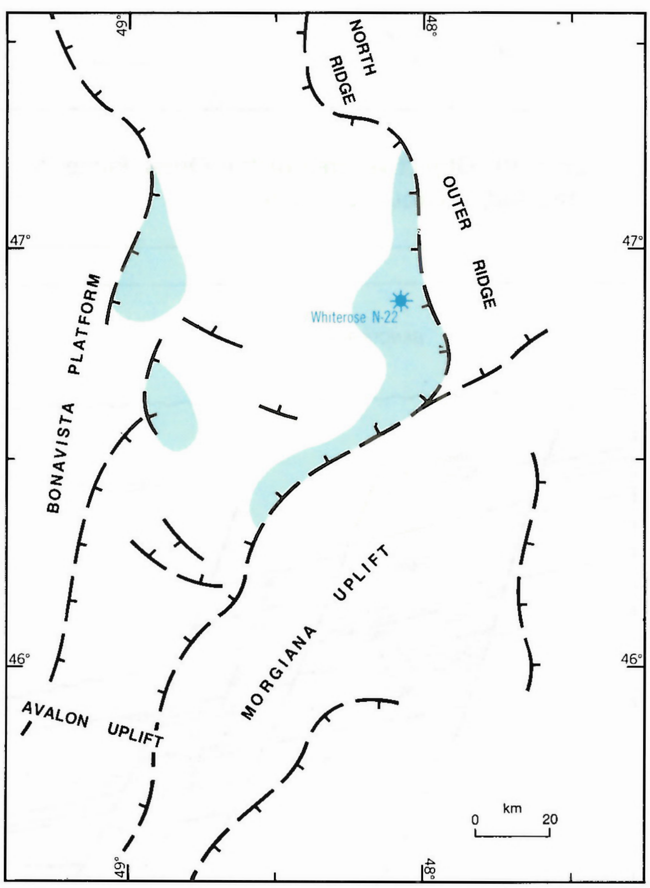

Figure 28. Objective areas of the Avalon/Ben Nevis formations in the Basin Margins Group of plays.

Most movement on faults defining the basin margins occurred during the Aptian–Albian, synchronous with deposition of the Ben Nevis and Nautilus formations. This is indicated by thickening into, and rapid thickness changes across, basin-bounding faults. In grabens, this period of faulting created hydrocarbon traps with the Avalon/Ben Nevis sandstones down-faulted against Whiterose Shale and "B" Marker limestone (Fig. 29). In horsts, the sandstones were upthrown against Nautilus Shale. Due to synchronous growth of faults with deposition, the Avalon/Ben Nevis sandstones are often not completely offset across faults, resulting in a lack of lateral seal. The Nautilus Shale provides an effective vertical seal for the Avalon/Ben Nevis traps. The faults defining this play provide potential vertical migration pathways for hydrocarbons generated in the underlying Egret Member. The Egret Member is mature over much of the Basin Margin play area but may be overmature basinward of the Whiterose structure. Lateral migration of hydrocarbons from this deep area may account for the large volume of gas encountered in the Whiterose structure.

Exploration history. Seven structures on the Basin Margins have been drilled in the Avalon/Ben Nevis formations. In order of drilling these are: Rankin, Terra Nova, Voyager, Archer, Whiterose, Mercury, and Bonne Bay. The Ben Nevis Formation was not found at the Egret well location because this area was uplifted and eroded during the Aptian–Albian period. A gas and condensate discovery was made in the Avalon/Ben Nevis reservoir in late 1984 by the Husky-Bow Valley et al. Whiterose N-22 well (Fig. 13). An offset well (J-49) drilled in late 1985 yielded oil and gas from the Avalon/Ben Nevis reservoir. In mid-1988, the E-09 well yielded oil from a 205 m hydrocarbon (oil and gas) column.

Summary. Sandstone, thickened due to synchronous growth of faults, may combine with adequate traps to yield a high volume of pooled hydrocarbons in the Avalon/Ben Nevis reservoir in remaining prospects. A detracting aspect of this play is the uncertainty of an adequate seal. Also the decrease in reservoir quality upward may result in production difficulties.

RIDGE GROUP

The Ridge Group contains two plays, called the Outer Ridge and the North Ridge. These ridges are part of the Outer Ridge Complex. This Complex, from south to north, is divided into the Morgiana Uplift, Outer Ridge, Ragnar Low, and North Ridge (Fig. 30).

The Outer Ridge Complex is a folded and faulted sequence of mainly Jurassic and Paleozoic sediments overlain by undisturbed Tertiary sediments.

Outer Ridge

Play definition. The Outer Ridge is a highly faulted, north-trending, structural high situated between the shallow basement of the Morgiana High to the south and a thick sequence of Lower Cretaceous sediments in the Ragnar Low to the north (Fig. 30). The sediments comprising the upper, drilled section of the ridge are mainly Jurassic. Reservoirs are found in Kimmeridgian sandstone of the Rankin Formation (Fig. 31), as well as in locally preserved Hibernia Formation in intraridge lows, and possibly in Middle Jurassic clastic rocks of the Voyager Formation.

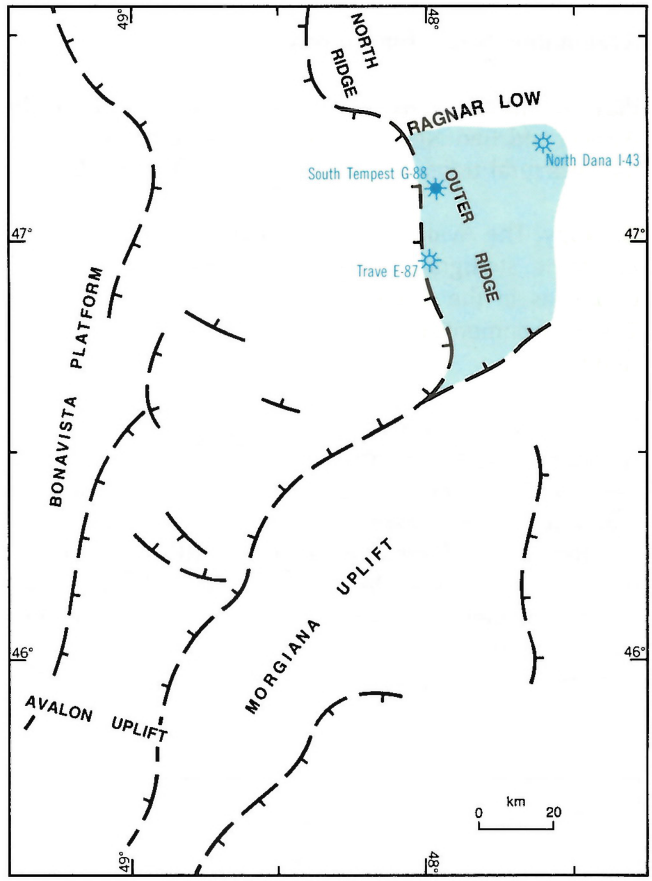

Figure 30. Objective area of the Outer Ridge in the Ridge Group of plays.

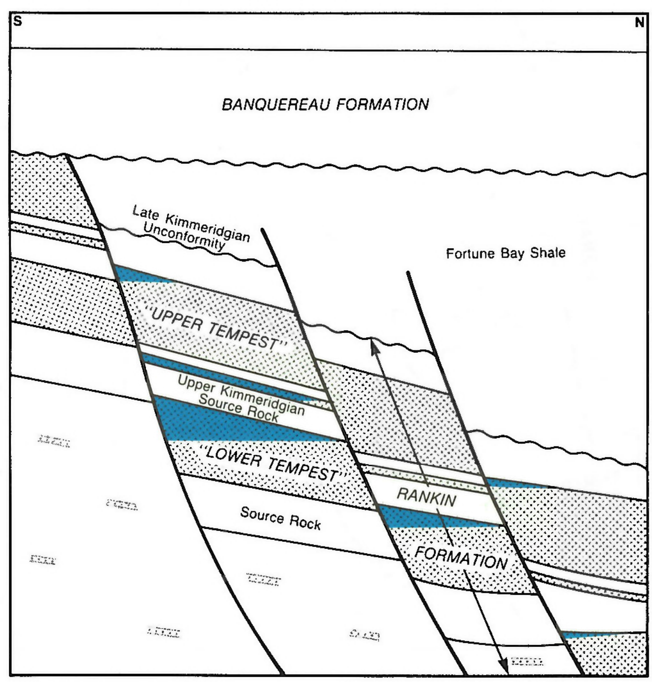

Figure 31. Schematic cross-section of the Outer Ridge play, illustrating possible trap types.

Geology. Limestone of the Rankin Formation in the Jeanne d'Arc Basin grades laterally to shale with interbeds of poorly sorted, fine to very coarse grained, variably coaly sandstone and thin, shaly limestone in the Outer Ridge area. Sandstone strata of Late Jurassic age are best developed in South Tempest G-88. These clastic rocks can be divided into two sandstone intervals, each underlain by an organic-rich source rock. The poor sorting, coarse grain size, carbonaceous debris, and discontinuous nature of the sandstone facies deposited with organic-rich shale suggest deposition by submarine fans or delta-fed turbidites in a stagnant, anoxic basin.

Net pays encountered to date in the Upper Jurassic sandstone are thin (about 12 m) and porosity in these clastic rocks averages between 12 and 16 per cent.

Thinly interbedded shale and very fine to fine grained, shaly, calcite-cemented sandstone make up the Hibernia Formation in Trave E-87, located on the western margin of the Outer Ridge. These sediments likely represent the cyclic incursion of distal delta front sediments of the Hibernia Formation into prodelta shales. The northerly location of the Trave structure, far from the major sediment source area (Avalon Uplift), likely accounts for the poor reservoir development. This sequence is partially preserved in the Trave structure and possibly in other intraridge lows, but is totally removed from, or was not deposited over, most of the Outer Ridge. It is capped by shale of the Tertiary Banquereau Formation.

Only 9 m of net pay, with an average porosity of 16 per cent, was encountered in the Hibernia Formation of the Trave structure.

The Voyager Formation, comprising interbedded sandstone, limestone, and shale, prograded over the Downing Formation during the Middle Jurassic. It was probably deposited prior to the uplift of the Outer Ridge and its depositional trends are likely independent of the present day morphology of the Jeanne d'Arc Basin and its margins.

Average porosity is very low (3%) in the Voyager Formation sandstone in Golconda C-64 and no hydrocarbons have been encountered in this formation to date.

Faults bounding and dissecting the Outer Ridge were initiated during the latest Jurassic and Early Cretaceous. Of the reservoirs discussed above, only the Hibernia Formation was deposited during a period of tectonic activity. This resulted in thinner Hibernia sandstone deposited over the Outer Ridge as compared to the adjacent Jeanne d'Arc Basin. Uplift, tilting, and erosion removed much of the Cretaceous and Jurassic sediments from the Outer Ridge area during the Aptian–Albian. Uplift was so great during this period that parts of the ridge did not become submerged during post-Albian regional subsidence until Eocene time. The faulting created hydrocarbon traps, mainly by downfaulting sandstone against shale interbeds of the Rankin Formation (Fig. 31). The lower Rankin sandstone strata are liable to be sealed against still older Jurassic shale, whereas the upper sandstone strata may lack lateral seal due to juxtaposition with lower sandstone. The faults provide potential vertical migration pathways to the Hibernia Formation reservoirs, in contrast to Kimmeridgian sandstone reservoirs, which may be fed either directly from encasing bituminous shale or via fault conduits from deeper, more mature source rocks in adjacent blocks. The Voyager Formation could have had a lateral source if an adjacent block had been downthrown sufficiently to place the Voyager Formation clastic rocks and the younger Kimmeridgian source rocks in juxtaposition.

Exploration history. Four structures on the Outer Ridge have been drilled. In order of drilling these are: South Tempest, Trave, Panther, and Golconda. For the purposes of this assessment, the North Dana and Lancaster structures, located just east of the Outer Ridge, are also included. In early 1981, South Tempest G-88 tested oil (about 40° API) from three zones in Kimmeridgian sandstone (Fig. 13). In late 1983, North Dana I-43 tested gas and condensate (52.7° API) from the lower Kimmeridgian sandstone. In mid-1984, Trave E-87 flowed gas and condensate (about 70° API) from the Hibernia Formation.

Summary. Thick, reservoir quality, Upper Jurassic sandstone may be locally deposited in the Outer Ridge area and provide a high potential target. The high risk of poor lateral seal and the unpredictability of reservoir facies in this interval, however, result in a high risk associated with such targets.

North Ridge

Play definition. The North Ridge is a north-south-trending, Paleozoic basement-cored high located north of the Ragnar Low (Fig. 32). This play includes all structural prospects (horsts and anticlines) over the high and on the flanking margins. The play also includes a number of large, poorly defined, domal and tilted structures to the east. These may be related to either

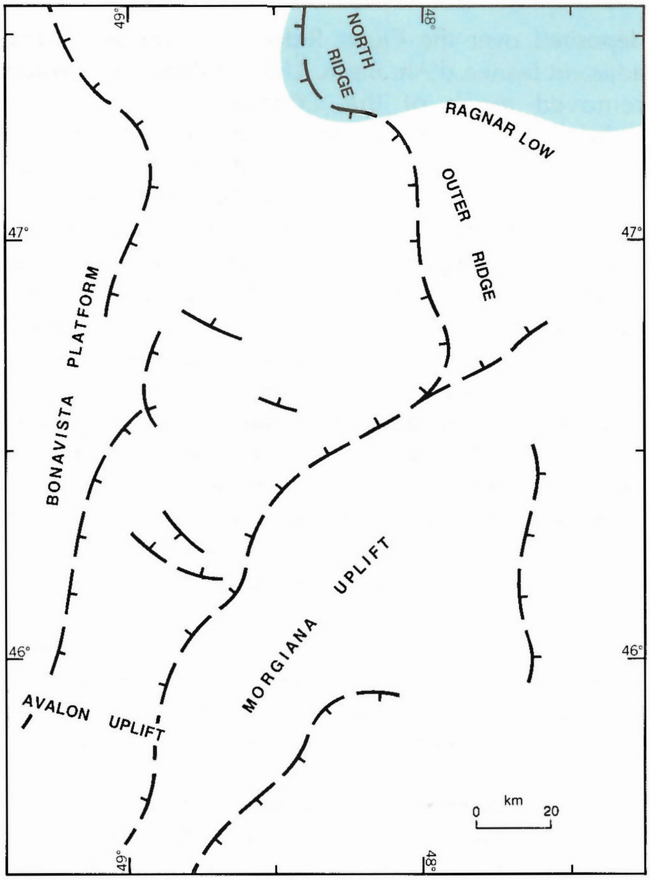

Figure 32. Objective area of the North Ridge in the Ridge Group of plays.

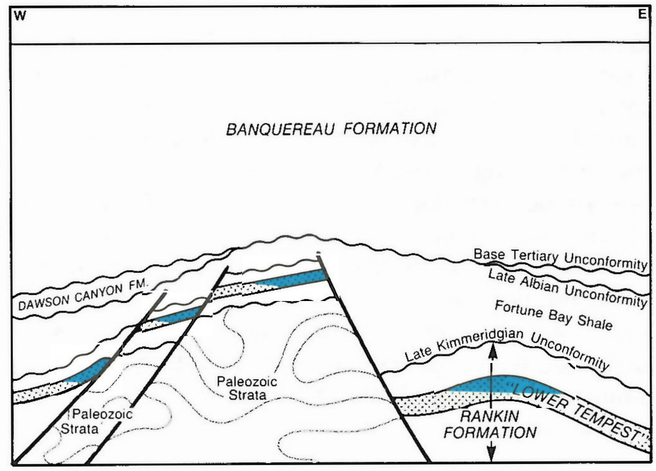

Figure 33. Schematic cross-section of the North Ridge play illustrating the trap types.

basement or salt movement. Sandstone of the Rankin Formation provides reservoirs in this area (Fig. 33).

Geology. Limestone of the Rankin Formation in the Jeanne d'Arc Basin grades laterally to shale with interbeds of poorly sorted, fine to very coarse grained, variably coaly sandstone and thin, shaly limestone in the Outer Ridge and North Ridge areas. Sandstone strata of Late Jurassic age are best developed in South Tempest G-88. These clastic rocks can be divided into two sandstone intervals, each underlain by organic-rich source rocks. The poor sorting, coarse grain size, carbonaceous debris, and discontinuous nature of the sandstone facies deposited with organic-rich shale suggest deposition by submarine fans or delta-fed turbidites in a stagnant, anoxic basin.

Thirty-eight metres of Upper Jurassic sandstone were encountered in Bonanza M-71, of which approximately 17 m were porous. Porosity averaged 9 per cent.

Faulting occurred during the Early Cretaceous. This created potential hydrocarbon traps with the Upper Jurassic sandstone, both in grabens, downfaulted against older Mesozoic shale and Paleozoic basement, and in horsts, upthrown against Lower Cretaceous shale. Shale of the Jurassic Rankin Formation and of the Lower Cretaceous also provide effective top seals. Migration of hydrocarbons may be either lateral, from the interbedded source rocks, or vertical, along faults from deeper areas such as those flanking the North Ridge. Gas is the most likely product of overmature organics in such deep margins.

Exploration history. Only two wells have been drilled in the North Ridge play area. The Dominion O-23 well, drilled in late 1974, penetrated thick Lower Cretaceous shale on the southern flank of the high. In 1982, Bonanza M-71 penetrated thin sandstone in thick Upper Jurassic shale and stopped in altered (chloritized) shale of the basement. An 18 m thick interval of silica-cemented sandstone with patchy dark or dead oil staining and occasional yellow fluorescence was drill stem tested in this well. It flowed water.

Summary. Jurassic sandstone of reservoir grade or as yet undiscovered Cretaceous sandstone reservoirs are required to improve the prospects of this play.

NORTH JEANNE D'ARC BASIN GROUP

The north part of the Jeanne d'Arc Basin — mainly north of 47°N — contains fewer porous clastic rocks suitable for trapping hydrocarbons, compared with the southern part of the basin. There are, however, trapping mechanisms associated with salt diapirs and with major faulting. There are two plays in this group: salt diapirs and fault structures.

Salt diapirs

Play definition. The North Jeanne d'Arc–Salt Diapir objective occupies the major depocentre in the northern part of the Jeanne d'Arc Basin (Fig. 34). Possible traps occur in upturned beds pierced by the diapirs and in reservoir beds draped or domed over the salt. Possible reservoir targets are sandstone strata in the Upper Cretaceous Dawson Canyon Formation and the Lower Cretaceous Ben Nevis Formation (Fig. 35).

Geology. The North Jeanne d'Arc–Salt Diapir objective area is distal to the main sediment source area (i.e., Avalon Uplift). As a result, strata equivalent to the Jeanne d'Arc and Hibernia formations are apt to be basinal shales in this area. It may be possible that thin sandstone strata of the Ben Nevis Formation are present, although these have not yet been penetrated. The only reservoir clastic rocks encountered to date were very thin, very fine grained sandstone, interbedded with thick shale of the Dawson Canyon Formation in Adolphus 2K-41. Reservoir quality is likely to be low throughout this area.

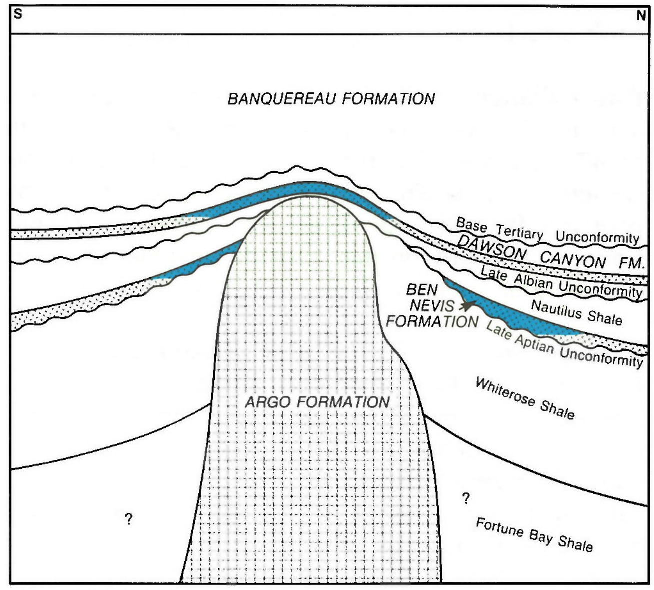

Figure 35. Schematic cross-section of a salt diapir prospect and related trap types in the North Jeanne d'Arc Group of plays.

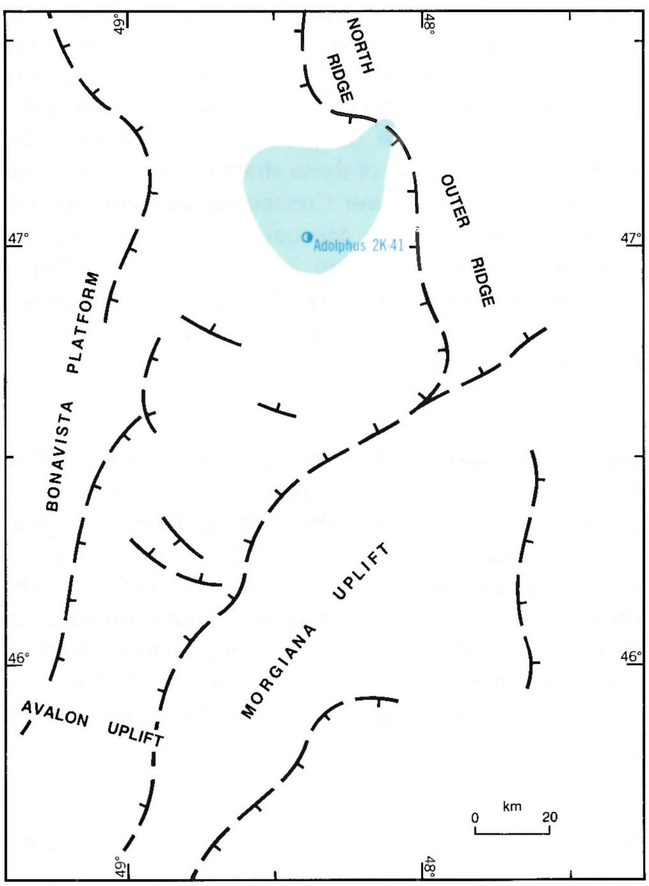

Figure 34. Objective area of the salt diapir in the North Jeanne d'Arc Group of plays.

Jurassic source rocks reached maturity earliest in this area of the Jeanne d'Arc Basin. Oil generated during early stages of maturity could have migrated into traps formed by early salt movement. The Kimmeridgian source rocks have since become overmature and are most likely gas-generating at present. Highly organic shale of the lower Tertiary may be mature in this area due to greater depth of burial compared to more southerly areas of the Jeanne d'Arc Basin. The possibility that these Tertiary sediments provide a source rock for gas cannot be discounted. Thick Cretaceous and Tertiary shales provide vertical seals. Faulting due to late salt movement, however, may have resulted in a loss of seal in traps formed earlier.

Exploration history. Adolphus 2K-41 tested low rates (42.6 m^3/d, 268 BPD) of 31° API oil from near the crest of a salt diapir in late 1973 (Fig. 13). The exploratory well Adolphus D-50, tested downdip on the same diapir, was declared dry and was abandoned in early 1975. A second salt dome was tested by the Conquest K-09 well, but this was also declared dry in mid-1985 and was abandoned in early 1986, although high mud gas (C_1 to C_4) levels were measured at 3940–3965 m during drilling of Lower Cretaceous shale.

Summary. Poor reservoir quality of the sands, possible breach of seal, and overmaturity of source rocks are all considered to detract seriously from any advantages of this play. Therefore it is considered to be of high risk.

Fault structures

Play definition. This play includes the fault-bound horst and tilted blocks formed in the Jeanne d'Arc Basin north of 47° latitude (Fig. 36) including blocks along the western basin margin. Lower Cretaceous sandstone may provide fault-bound reservoirs, whereas Upper Cretaceous sandstone may provide possible reservoirs draped over structural highs (Fig. 37).

Geology. The area has not been widely explored. The Flying Foam I-13 well shows this area to be distant from clastic input during deposition of both the Jeanne d'Arc and Hibernia formations. Avalon/Ben Nevis sandstones may be present in grabens between the structural highs. Sandstone was deposited in surrounding areas during the Upper Cretaceous and may provide a potential reservoir.

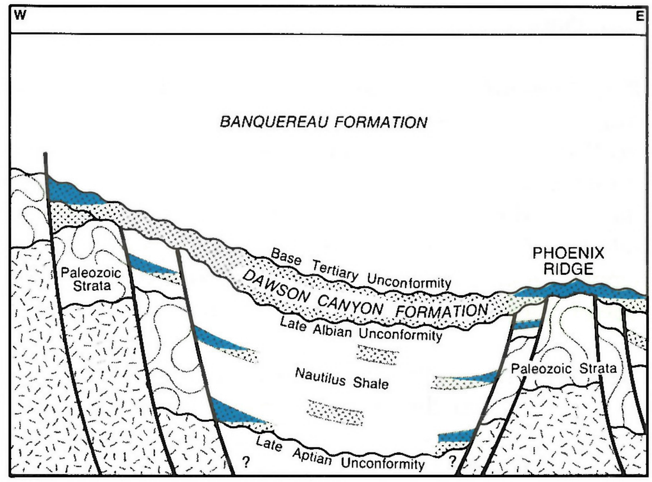

Figure 37. Schematic cross-section illustrating fault structure trap types in the North Jeanne d'Arc Group of plays.

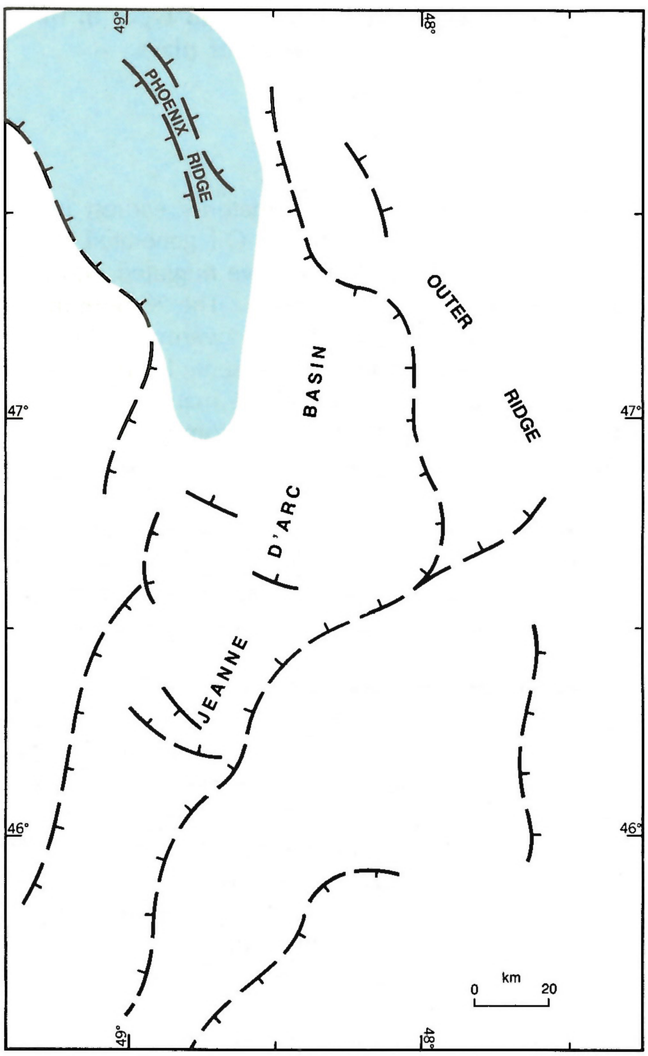

Figure 36. Objective area of possible North Jeanne d'Arc Basin fault structures.

The Egret Member source rock is present in the Flying Foam I-13 well, but its deposition and preservation to the north is uncertain. Lower Tertiary strata have a high organic component and may constitute mature hydrocarbon source rocks in the North Jeanne d'Arc area, where they are deeply buried. However, the hydrocarbon potential of these strata is equivocal. Traps may be formed by Lower Cretaceous sandstone down-faulted against older Mesozoic strata or against metamorphosed Paleozoic strata (Fig. 37). Upper Cretaceous reservoirs may display closure below Tertiary shale as a result of drape over Paleozoic salt or basement horst highs.

Exploration history. Only the Flying Foam Ridge tilted block has been tested in this play. Flying Foam I-13 was drilled in late 1973 and West Flying Foam L-23 was drilled in late 1981 to early 1982. Neither of these wells encountered significant reservoir facies in the thick, shale-dominated Mesozoic strata penetrated. Paleozoic, tilted fault blocks were encountered north of the Jeanne d'Arc Basin in Cumberland B-55. The only reservoir horizon encountered in this well was in sandstone of the Upper Cretaceous.

Summary. The uncertainty of the presence of source rock and reservoir rock are major risks to this play. Wells have not yet been drilled in the grabens between structural highs in this play area to test the presence or absence of reservoir rock.

STRATIGRAPHIC TRAPS GROUP

Three stratigraphic plays have been identified in the Jeanne d'Arc Basin. The oldest is in the Jurassic Jeanne d'Arc Formation. Above it are sandstone plays of the Lower Cretaceous, followed still higher in the section by sandstone plays of the Upper Cretaceous and Tertiary.

Jeanne d'Arc Formation pinch-out

Play definition. This play includes all pools and prospects in sandstone and conglomerate of the Jeanne d'Arc Formation where it pinches out against highs along the southern margin of the Jeanne d'Arc Basin (Figs. 38, 39). These stratigraphic traps may locally involve structural components such as fault-tilting of blocks.

Geology. The Jeanne d'Arc Formation comprises alluvial to braided fluvial and deltaic conglomerate, sandstone, and shale. These unconformably overlie limestone of the Rankin Formation and are conformably overlain by the Fortune Bay Shale. At the southern end of the Jeanne d'Arc Basin, wide valleys were deeply cut into older sediments. The clastic rocks were deposited as a northward-thickening wedge of stacked channel sandstone, erratic conglomerate beds, and basinal shale with thin sandstone stringers. The sandstone and conglomerate onlap the Avalon Uplift and Morgiana Uplift (Fig. 38) and are overstepped by the Fortune Bay Shale as encountered in Port au Port J-97. Channel sandstones, such as those penetrated by Gambo N-70, are also included in this play.

The Jeanne d'Arc sandstone units of this play are thin but can have high porosity due to their relatively shallow depth of burial. In Beothuk M-05, 8.5 m of net pay, which had an average porosity of 19 per cent, were encountered.

Long distance lateral migration of hydrocarbons may have been necessary to fill these relatively shallow traps with oil generated in mature Upper Jurassic source rocks to the north. The overlying Fortune Bay Shale provides the seal for these stratigraphic traps.

Exploration history. Four prospects have been drilled in the Jeanne d'Arc pinch-out objective area. In order of drilling these are: Egret, Port au Port, Beothuk, and Gambo. Port au Port J-97 did not encounter reservoir conditions because the well was located south of the pinch-out against the northern flank of the Avalon Uplift. In early 1985, the Beothuk M-05 well flowed oil from two intervals in the Jeanne d'Arc Formation.

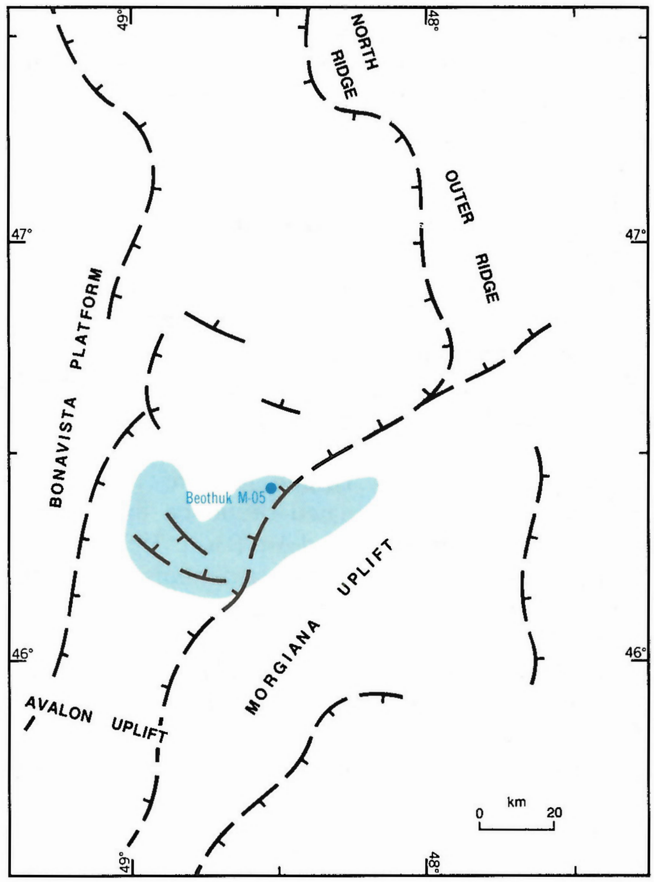

Figure 38. Objective area of the Jeanne d'Arc Formation pinch-out play in the Stratigraphic Traps Group of plays.

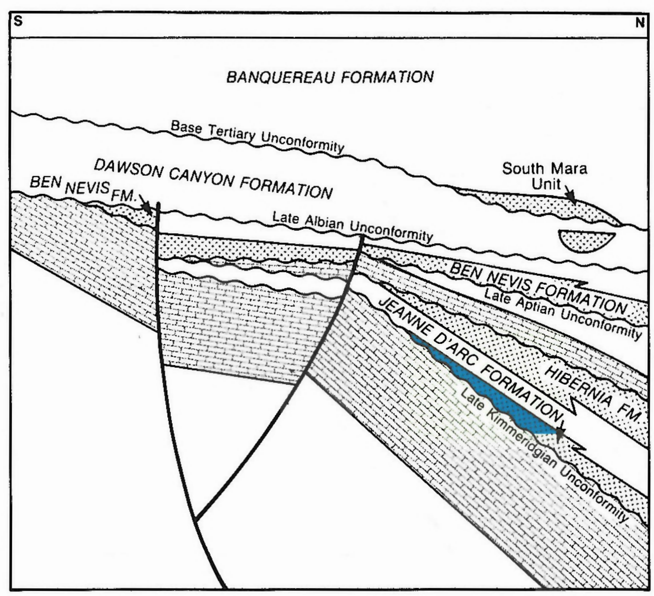

Figure 39. Schematic cross-section illustrating the trap type in the Jeanne d'Arc Formation in the Stratigraphic Traps Group of plays.

Summary. This play has moderate potential, but difficulties in mapping updip reservoir limits and the lack of underlying mature source rocks make it a high risk play.

Subcrop of Lower Cretaceous sandstone

Play definition. This play includes all prospects in sandstones of Early Cretaceous age where they subcrop below unconformities at the southern end of the Jeanne d'Arc Basin (Fig. 40). Reservoirs occur in the Hibernia and Avalon/Ben Nevis formations (Fig. 41).

Geology. The entire Upper Jurassic and Lower Cretaceous clastic-dominated sequence thins in the southern part of the Jeanne d'Arc Basin. This is due to subsequent erosion of these sediments along the northern flank of the Avalon Uplift.

The Hibernia Formation in this play area generally comprises thin, fine grained sandstone, preserved

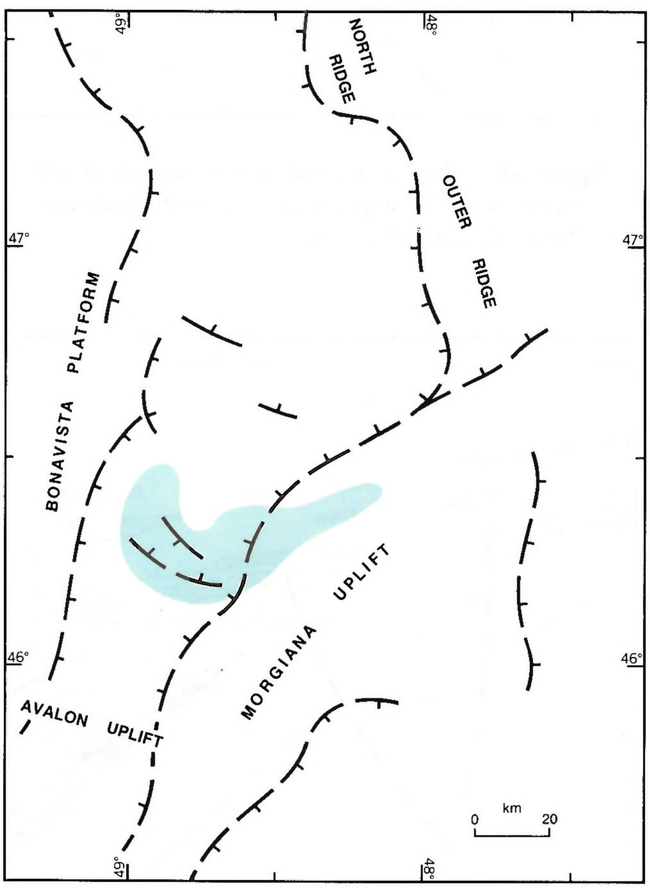

Figure 40. Objective area of the Lower Cretaceous sandstone subcrop play in the Stratigraphic Traps Group of plays.

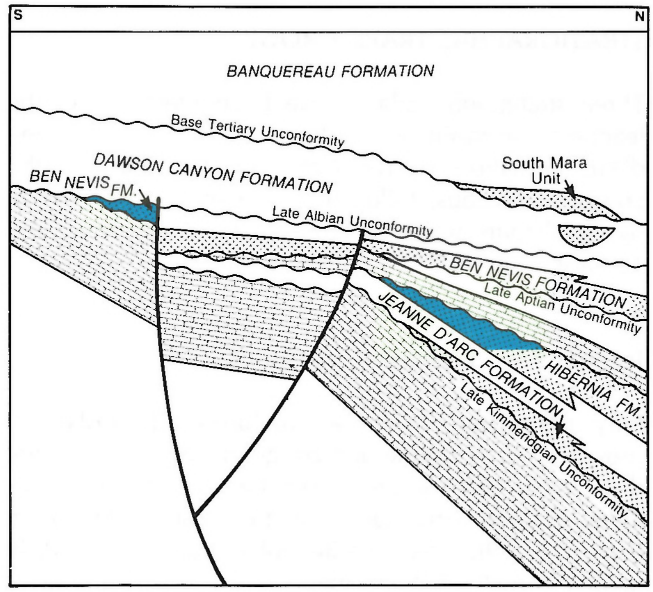

Figure 41. Schematic cross-section illustrating the trap type in the Lower Cretaceous sandstone play in the Stratigraphic Traps Group of plays.

below an unconformity at the base of the "B" Marker limestone as encountered in Gambo N-70. Some coarse grained channel sandstones may be preserved where the Hibernia Formation subcrops steeply below the unconformity, as in Egret N-46 (Fig. 41). Very fine to coarse grained sandstone of the Avalon/Ben Nevis reservoir subcrop below the late Albian unconformity.

Reservoir quality is likely to be variable in this play. The Hibernia Formation may be highly porous (over 30%) due to its shallow burial depth, but this porosity generally occurs in thin sandstone beds within shale. The Avalon/Ben Nevis reservoir may be highly porous because of its shallow burial depth.

"B" Marker limestone and Dawson Canyon Formation shale provide vertical seals for these reservoirs. The Egret Member is apt to be immature over much of the area of this subcrop play. This play, therefore, requires the lateral migration of hydrocarbons from more deeply subsided areas to the north.

Exploration history. Three prospects have been drilled in this play: Egret, Port au Port, and Gambo. All three were dry.

Summary. This play has moderate potential, but the variability in sediment quality, difficulties in mapping updip reservoir limits, and the lack of underlying mature source rocks make this a high risk play.

Shale-bounded sandstone

Play definition. This play includes all pools and prospects in lower Tertiary (South Mara) and Upper Cretaceous sandstone encased in shale anywhere in the Jeanne d'Arc Basin or on the basin margins (Figs. 42, 43).

Geology. A Paleocene to lower Eocene submarine fan complex with associated canyons is recognized on the western flank of the Jeanne d'Arc Basin. Fine to coarse grained South Mara sandstone appears to comprise clastic rocks of the Upper Cretaceous delta/shelf system that were reworked by erosion. Drilling and seismic data indicate that the sandstones of such reservoirs may have been widely, though erratically, deposited throughout the objective area. Shales of the Banquereau Formation provide seals. Upper Cretaceous sandstone may be locally encased in shale of the Dawson Canyon Formation.

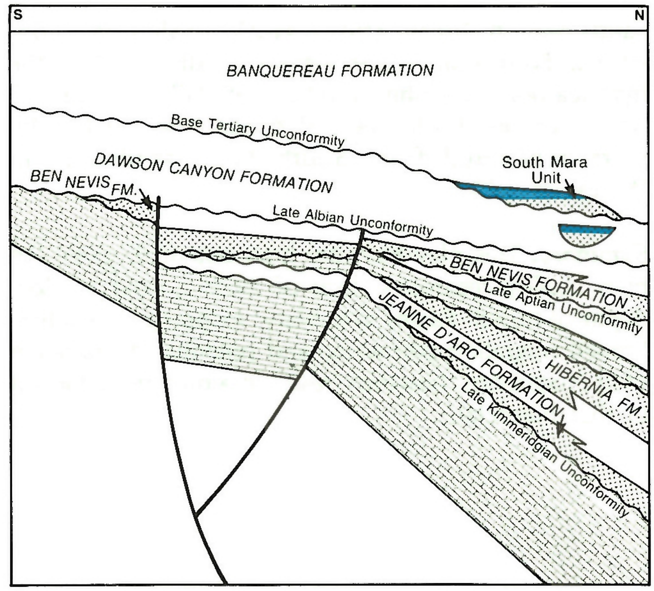

Figure 43. Schematic cross-section illustrating the trap type of the Upper Cretaceous and Tertiary sandstones of the Stratigraphic Traps Group of plays.

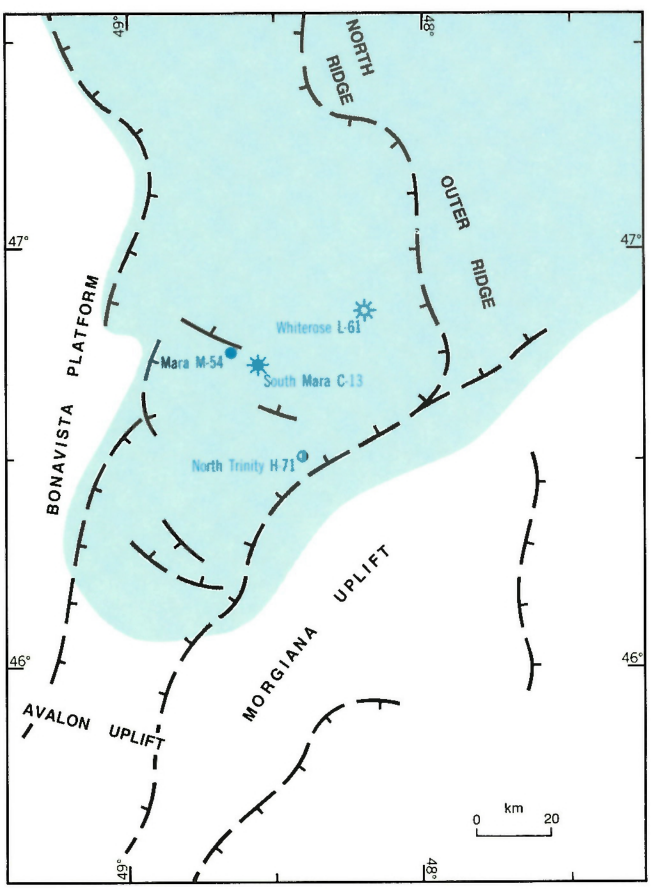

Figure 42. Objective area of the shale-bounded sandstones classed in the Stratigraphic Traps Group of plays.

The reservoir quality of the South Mara sandstone is extremely variable. Massive sandstone units displaying over 30 m of continuous porosity averaging 30 per cent have been penetrated (i.e., South Mara C-13).

Although these sediments were deposited after the last tectonic episode in the Jeanne d'Arc Basin, faults caused by sediment loading and variable amounts of sediment compaction do locally offset these shallow horizons. Such faults provide potential vertical migration pathways from Jurassic hydrocarbon source rocks.

Highly organic Tertiary shale may provide an alternative source rock in the deeper parts of the basin where these sediments are mature. However, the hydrocarbon potential of these lower Tertiary sediments is equivocal. The occurrence of heavy oil in South Mara sandstone in North Trinity H-71 indicates that oil quality may locally (i.e., in areas of low burial depth) be a problem with this play.

Exploration history. Wireline logs indicated the presence of hydrocarbons over a 1 m interval at the top of a 30 m thick porous sandstone in South Mara C-13. Formation water with traces of hydrocarbons was recovered in a late 1984 test of this interval. In early 1985, oil was recovered from both Dawson Canyon (20.5° API) and South Mara sandstones (21.6° API) in Mara M-54 (Fig. 13). About 7 m of hydrocarbon show were identified by wireline logs over South Mara sandstone in North Trinity H-71, drilled in 1985. Repeat Formation Tester samples indicated that the hydrocarbons were heavy oil (11.9° API) with an H_2S odour. In late 1986, gas and condensate (70.4° API) were recovered from South Mara sandstone in Whiterose L-61.

Summary. This play has very high potential, given the high quality reservoirs, lack of faulting, and shallow depth of burial. Facies variability, mapping difficulties, limited migration pathways, and potential degradation of hydrocarbons, however, result in a high risk attached to that potential.

ESTIMATES OF TOTAL RESOURCES

Part II of *Petroleum Resources of the Jeanne d'Arc Basin and Environs, Grand Banks, Newfoundland* provides estimates of the total hydrocarbon resources of the area, based on statistical modelling of reservoir and trap data (from well and seismic data) for each play. Remaining hydrocarbon potential estimates are also provided, based on subtraction of discovered resource estimates from the total hydrocarbon endowment estimates.

PART II: HYDROCARBON POTENTIAL

INTRODUCTION

This report has been prepared on behalf of the Petroleum Potential Committee of the Petroleum Resource Appraisal Secretariat. The resource estimates presented are based on multidisciplinary studies made by a group that was formed to examine the petroleum geology of the Jeanne d'Arc Basin, with particular focus on the opportunities for the entrapment of hydrocarbons. The Basin Analysis Group was formed from the staffs of the Canada-Newfoundland Offshore Petroleum Board (CNOPB), Canada Oil and Gas Lands Administration (COGLA), Newfoundland Department of Energy (Nfld. Dept. Energy), and the Geological Survey of Canada (GSC). Members included: N.J. McMillan (Chairman, GSC, Calgary); G.R. Campbell (NEB, Calgary); S. Gower (CNOPB, St. John's); D. Hawkins (Nfld. Dept. Energy, St. John's); K.D. McAlpine (GSC, Dartmouth); G. Morrell (COGLA, Ottawa); D.F. Sherwin (CNOPB, St. John's); I.K. Sinclair (CNOPB, St. John's).

The Evaluation Subcommittee, those responsible for the resource estimates contained in this report consisted of: G.C. Taylor (Chairman, GSC, Calgary); M.E. Best (GSC, Dartmouth); G.R. Campbell (COGLA, Ottawa); J.P. Hea (EMR, Ottawa); D. Henao (CNOPB, St. John's); R.M. Procter (GSC, Calgary).

GEOLOGICAL SETTING

The Jeanne d'Arc Basin is situated on the Grand Banks of Newfoundland about 300 km east-southeast of the city of St. John's. The basin floor consists of continental crust developed during the Appalachian Orogeny, when a series of Mesozoic and Tertiary depocentres developed in response to seafloor spreading in the Atlantic, and subsequently Labrador, oceanic terranes. The Jeanne d'Arc Basin (Fig. 44) is the most northerly of a series of narrow, elongate, northeasterly trending basins with interconnected depocentres, and spills northeastward into the much larger East Newfoundland Basin.

Seafloor spreading began in the Atlantic south of the Grand Banks during the Early Jurassic and progressed from south to north. Spreading in the North Atlantic was initiated during the Early Cretaceous, and by the Late Cretaceous continental separation was complete. The two major cycles of rifting produced depositional wedges of coarse clastics that filled the basin longitudinally from the southeast. These sandstone deposits formed the principal reservoirs in the Jeanne d'Arc Basin. Source rocks were deposited during a Late Jurassic period of quiescence between the rifting cycles.

Evaporitic deposits, which were among the first deposits of the proto-basins, responded to later depositional loading by vertical (and probably horizontal) movement that initiated growth-faulting as compensation for salt removal. These faults, in combination with the tectonically generated faults that defined the basin, created the traps into which the maturing hydrocarbons could migrate.

PETROLEUM GEOLOGY

A review of the basin analysis team's synthesis of the geology in conjunction with the known history of drilling and discovery enabled the committee to define 15 exploration plays as the framework for an assessment of the hydrocarbon resources of the basin. These plays fall naturally into five separate play groups, and although the analysis was conducted at the individual play level, the results have been combined at the play group level, and are so reported here.

The first of the play groups, named the *Trans-Basin Fault Trend Group*, consists of five separate plays that correspond to different reservoir packages that could exist in any given structure within the family of structures that define the trans-basin trend of faults (Fig. 44). Similarly, the *Basin Margins Group* consists of three separate plays that correspond to different reservoir packages that may occur in any of the structures associated with the Basin Margins Group family of faults. Structures of this play group occur on both east and west sides of the Jeanne d'Arc Basin (Fig. 44). The two plays that make up the *Ridge Group* (Fig. 44) are defined geographically, separated by the east-west trending Ragnar Depression. Within the deeper portion of the basin, the *North Jeanne d'Arc Basin Group* consists of one play associated with the intrusion of salt diapirs, and a second play associated with complex fault structures in that part of the basin (Fig. 44). The remaining play group, *Stratigraphic Traps*, consists of three plays that include separate families of stratigraphic traps (Fig. 44).

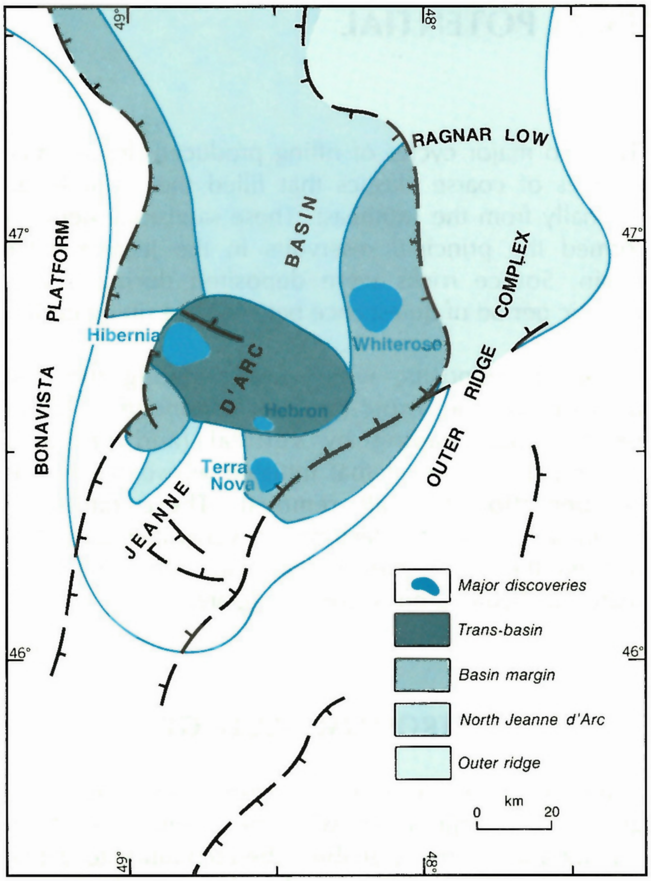

Figure 44. Sketch map showing boundaries of the exploration play groups and location of major discoveries.

ESTIMATES OF PETROLEUM RESOURCES

The purpose of this assessment was to determine the total quantity of oil that can be expected to exist in the Jeanne d'Arc Basin. This quantity, called the basin petroleum endowment, includes both what has already been found plus an undiscovered component, called potential, that can be inferred to exist on the basis of current understanding of the geology of the basin. The systematic approach used in the assessment process (Podruski et al., 1988, p. 8–13) results in estimates for each exploration play, including all size ranges of all pools expected to exist, regardless of whether they may be explored for, or, if discovered, be economically exploitable. The analytical procedure requires that pools that are obviously too small to be economically attractive be included in order to preserve the statistical integrity of the process.

The ability to predict the size range of individual pools that constitute the resource endowment is an important aspect of the methodology, because pool size is the main basis for subsequent economic analysis. No economic analysis has been undertaken in this report. However, in the discussion of important play groups below, the oil resource endowment is expressed in terms of three arbitrarily selected size classes. The number of pools and the quantity of oil expected to exist in size classes greater than 100 million barrels (16 10^6m^3), between 25 and 100 million barrels (4 and 16 10^6m^3), and less than 25 million barrels (4 10^6m^3) are given. It must be emphasized that the class sizes selected for this report have no foundation in real economic analysis but are used only to give some measure of the size dispersion of the resource.

Within this study, the emphasis has been on the oil, rather than the gas, resources. Each one of the exploration plays that involves mappable structures, i.e., all except the stratigraphic plays, was subjected to the full analytical process for oil. In each case, the total suite of predicted pool sizes was matched with the results of discovery and tested for geological acceptability. Estimates for the stratigraphic plays were made as a percentage of the total basin endowment, on the premise that in a basin containing ideal structures one can expect about 15 per cent of the resources to exist in stratigraphic traps. Field size analysis was not attempted for the stratigraphic plays. Estimates of oil endowment for individual plays were summed to create estimates for both play group totals as well as total basin endowment. Illustration and discussion of results have been restricted in this paper to basin totals and oil resource components of the more important play groups. In all cases, the resources reported are expressed as "technically recoverable" in contrast to "in place" volumes. The expression "technically recoverable" means the quantity of hydrocarbon that could be produced from a pool by both primary and normal secondary recovery (i.e., pressure maintenance) techniques, but excluding more exotic enhanced recovery methods.

JEANNE D'ARC BASIN AND ENVIRONS ENDOWMENT

The oil resources estimated to exist within the Jeanne d'Arc Basin assessment area are shown in Figure 45. The range in values shown represents the 50 per cent confidence interval for the estimates, i.e., there is a 75 per cent chance that the quantity estimated is at least 3.3 billion barrels (0.52 10^9m^3) and there is only a 25 per cent chance that the total amount exceeds 5.3 billion barrels (0.84 10^9m^3). It should be noted that higher and lower values exist beyond the 50 per cent confidence range, with appropriate levels of confidence. The figure also discriminates between that portion of the total endowment that has currently been

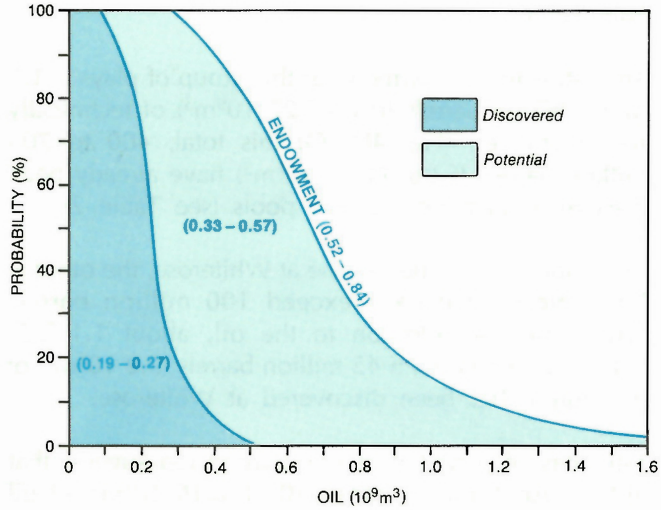

Figure 45. Distribution of estimates of total basin endowment, subdivided into discovered resources and potential. (Number in brackets 10^9m^3)

discovered (1.2–1.7 billion barrels; 0.19–0.27 10^9m^3) and the remaining potential (2.1–3.6 billion barrels; 0.33–0.57 10^9m^3). The discovered component describes the uncertainty that surrounds the median values listed in Table 2 for each discovered pool in the basin. In total, 21 pools have been discovered in 14 fields, totalling 1.5 billion barrels (0.24 10^9m^3) at a median value.

TRANS-BASIN FAULT TREND GROUP

Five plays constitute the Trans-Basin Fault Trend Group, each play being defined by a specific stratigraphic interval that contains potential reservoir rocks (see Fig. 44). The play group is defined by a series of structures that cross the southern region of the basin. These structures are related to normal faults associated with the removal of deep salt or to others relating to the rifting process. Most of these faults are down-to-the-basin-type growth faults, although a number of significant antithetic faults are also present. Because of different history of sedimentation, not all reservoir packages will be present in any specific structure. However, some degree of stacking of pools is considered likely in this play group, as in Hibernia, Hebron, and West Ben Nevis.

Endowment

The total endowment estimated for the five plays in this group is 1.3 to 2.2 billion barrels (0.21–0.35 10^9m^3) of technically recoverable oil (Fig. 46). The range in values quoted expresses the 50 per cent interval of confidence, i.e., for the lesser value there is a 75 per cent chance that the true value will be at least this large, and for the larger value quoted there is only a 25 per cent chance that the true value will exceed this amount.

Discovered oil resources amount to 700 to 1000 million barrels (112–160 10^6m^3) of oil located in 13 significant discoveries (see Table 2). These include two pools in the Hibernia field and one at Hebron that contain in excess of 100 million barrels (16 10^6m^3).

The remaining oil potential in this play group is estimated at 600 to 1500 million barrels (96–240 10^6m^3) of technically recoverable oil.

The estimates were prepared to include an estimate of the size ranges of individual pools expected in each play. That information is summarized in Figure 47. It was predicted that four pools would exceed 100 million barrels (16 10^6m^3), and of these, three have already been discovered. An additional nine pools of between 25 and 100 million barrels (4–16 10^6m^3) were predicted. Two of the pools in this size class have been discovered. It is significant to note that approximately 80 per cent of the total oil endowment of this play group is expected to occur in pools larger than 25 million barrels (4 10^6m^3). Such a concentration of resources is typical of the structural family of plays.

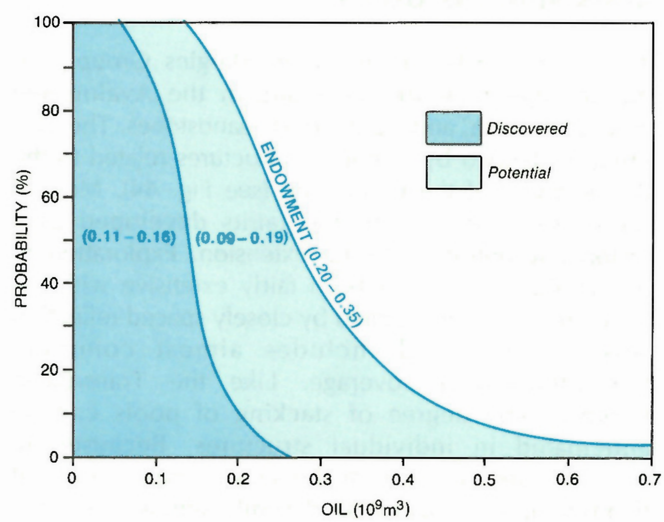

Figure 46. Distribution of estimates of total endowment for the five plays of the Trans-Basin Fault Trend Group, subdivided into discovered resources and potential. (Number in brackets 10^9m^3)

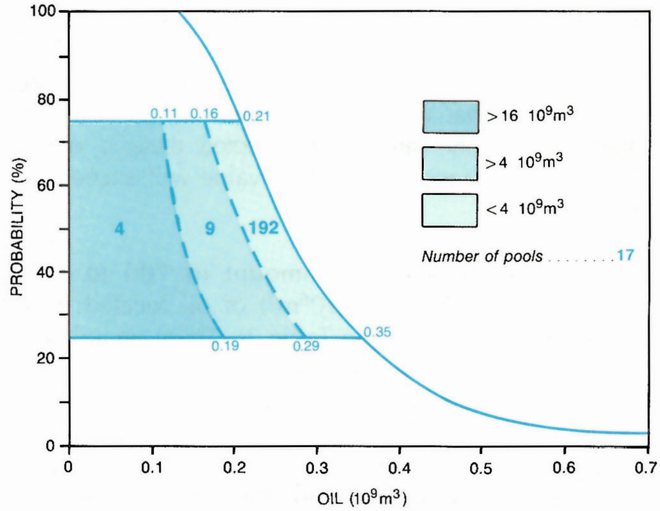

Figure 47. Distribution of estimates of total endowment for the Trans-Basin Fault Trend Group, illustrating the number and portions of the endowment expected to occur in pools of specified class sizes.

Although the focus of this report is on oil, exploration in this play group has also discovered more than 1.6 TCF (45.3 10^9m^3) of gas containing approximately 40 million barrels (6.3 10^6m^3) of gas liquids (Table 2).

BASIN MARGINS GROUP

Three plays make up the Basin Margins Group. The major objectives are reservoirs in the Avalon/Ben Nevis, Hibernia, and Jeanne d'Arc sandstones. The play group is defined by a series of structures related to the development of the basin itself (see Fig. 44). Most of these structures are normal faults developed as a tectonic response to crustal extension. Exploration in this group of plays has been fairly extensive with the structures well documented by closely spaced reflection seismic lines and includes almost complete three-dimensional coverage. Like the Trans-Basin Group, some degree of stacking of pools can be anticipated in individual structures. Because the structures are located near the sites of maximum sand deposition, sand against sand combinations across the faults can result in a loss of seal for some of the traps, limiting the size of potential accumulations. This appears to be the reason for the lack of hydrocarbons in some of the drilled prospects, particularly at the Hibernia reservoir level.

Endowment

The estimated endowment for this group of plays is 1.1 to 1.7 billion barrels (0.17–0.27 10^9m^3) of technically recoverable oil (Fig. 48). Of this total, 400 to 700 million barrels (63.6–111.3 10^6m^3) have already been discovered in a total of five pools (see Table 2).

These include two pools, one at Whiterose, the other at Terra Nova, that each exceed 100 million barrels (16 10^6m^3). In addition to the oil, about 1.1 TCF (31 10^9m^3) of gas with 45 million barrels (7.2 10^6m^3) of gas liquids has been discovered at Whiterose.

Estimates of potential in this play group suggest that 700 to 1000 million barrels (0.11–0.16 10^9m^3) of oil remain to be discovered (Fig. 48). Estimates of individual pool size predict that three pools having in excess of 100 million barrels (16 10^6m^3) of recoverable oil (Fig. 49) may exist. Two of the three pools in this class have already been discovered. In the size range of 25 to 100 million barrels (4–16 10^6m^3), 11 pools are predicted, of which only one has been discovered. Like the Trans-Basin Group, the Basin Margin Group of plays shows a strong concentration of the total endowment into a limited number of large pools.

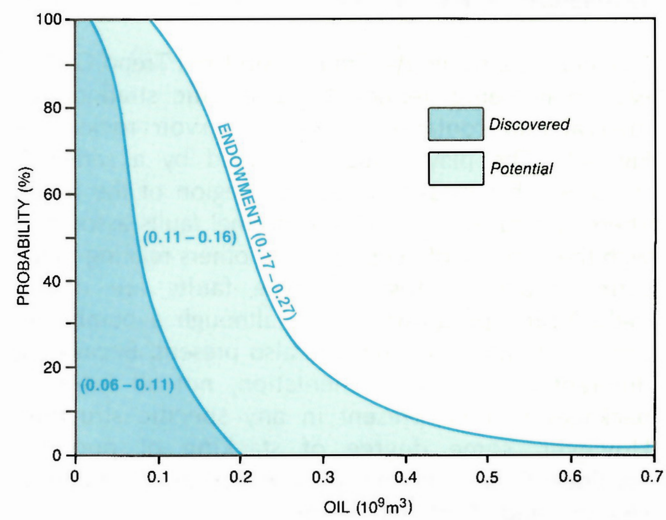

Figure 48. Distribution of estimates of total endowment for the three plays of the Basin Margins Group, subdivided into discovered resources and potential.

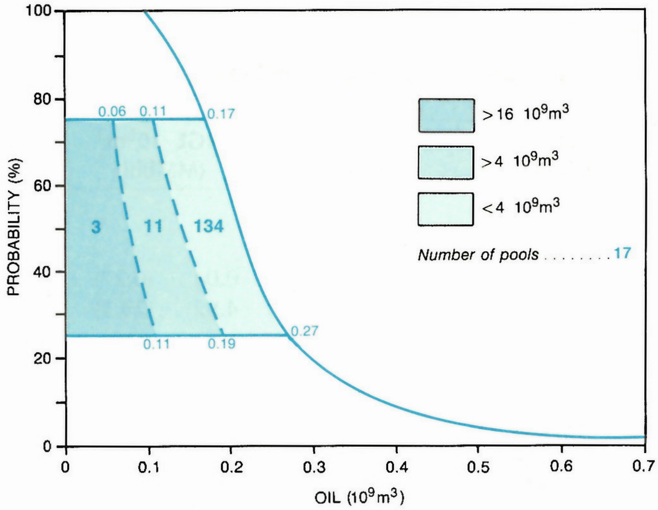

Figure 49. Distribution of estimates of total endowment for the Basin Margins Group, illustrating the numbers and portions of the endowment expected to occur in pools of specified class sizes.

RIDGE GROUP

Two plays, based on geographic criteria, make up the Ridge Group. The Outer Ridge play was defined to include those pools and prospects in structures that occur in the central section of the Outer Ridge Complex. It is separated from the North play along the axis of the Ragnar Depression. Both plays involve complex fault structures where the potential reservoir rocks are sandstones of the Voyager and/or Rankin formations. Relatively complete coverage by reflection seismic has defined most of the structures, which tend to be fragmented. Reservoir sandstones tend to be thinner in the Outer Ridge Complex than the sandstone reservoir packages of the Jeanne d'Arc Basin. Although the potential reservoir sandstones bracket the principal source rock interval of the region, the quality and maturity of the source rocks is poorly understood.

Endowment

The endowment estimated for this play group is 210 to 330 million barrels (33.4–52.4 10^6m^3). Because of the greater degree of uncertainty in our geological understanding of these plays, the distribution of potential has a maximum value in excess of one billion barrels, which although unlikely, could in fact exist.

Discovered oil resources amount to 6 to 11 million barrels (1.0–1.7 10^6m^3) in one discovery and a combined total of about 500 BCF (14 10^6m^3) of gas with 13 million barrels (2.1 10^6m^3) of associated liquids (Table 2) in two other discoveries.

The estimated potential of the play group is 204 to 220 million barrels (32–35 10^6m^3) of technically recoverable oil.

Maximum pool size estimated for this play group include three pools expected to be larger than 25 million barrels (4 10^6m^3) but none as large as 100 million barrels (16 10^6m^3).

NORTH JEANNE D'ARC BASIN GROUP

Two plays constitute the North Jeanne d'Arc Basin Group. Both are structural plays. The diapir play includes two families of prospects, one family associated with the diapirs themselves, the second with a group of fault structures that appear to be influenced by either salt removal, or salt thickening at depth. The second play includes faulted prospects associated with the horst that occurs in the Jeanne d'Arc Basin north of latitude 47°N, and additional prospects in tilted fault blocks along the western basin margin. The major risk in these plays concerns the presence of reservoirs with adequate net pay thickness to accumulate economic pool sizes. Secondary risks concern the adequacy of seal of potential traps because of the complex faulting.

Endowment

The total endowment estimated for the North Jeanne d'Arc Basin Group is 70 to 93 million barrels (11–15 10^6m^3). The full distribution of the potential for this play group also has a large maximum value (greater than 240 million barrels [38 10^6m^3]), which reflects the degree of uncertainty of our geological knowledge. Unlike most other parts of the basin, much of the play area is only covered by reconnaissance reflection seismic lines.

Only one discovery has been made in this play group: at Adolphus from a thin sandstone just beneath the Petrel Limestone, where about two million barrels of oil are indicated. The remaining play potential for this play group is estimated to be 67 to 91 million barrels (11–14 10^6m^3) of technically recoverable oil. This analysis would (admittedly based on limited data) suggest that there should be no accumulations in pools of sizes greater than 25 million barrels (4 10^6m^3).

TABLE 2

Discovered resources of oil, gas and natural gas liquids (ethane and higher)*

Pool Name	Formation	Oil 10^6m^3	(MMbbl)	Gas 10^9m^3	(BCF)	NGL 10^6m^3	(MMbbl)
Trans-Basin Group							
Ben Nevis	Ben Nevis	3.0	(18.9)				
Ben Nevis	Eastern Shoals ("A" Marker)			0.3	(10.1)	0.04	(0.27)
Ben Nevis	Hibernia (lower zone)			6.2	(218.0)	4.62	(29.1)
Hebron	Ben Nevis	20.2	(127.0)				
Hebron	Hibernia (upper zone)	7.2	(45.0)				
Hebron	Jeanne d'Arc	3.2	(19.9)	2.9	(102.0)		
Hibernia**	Avalon/Ben Nevis	28.9	(182.0)				
Hibernia***	Catalina	0.1	(0.6)	29.8	(1051.0)		
Hibernia**	Hibernia	76.9	(484.0)				
Hibernia	Jeanne d'Arc	0.8	(5.0)				
Nautilus		2.1	(13.2)	3.3	(115.0)	0.67	(4.2)
N. Ben Nevis		2.9	(18.4)	4.1	(144.0)	1.16	(7.3)
S. Mara		0.6	(3.6)				
W. Ben Nevis	Ben Nevis	0.6	(4.0)				
W. Ben Nevis	Eastern Shoals ("A" Marker)	3.3	(21.0)				
Basin Margins Group							
Bonne Bay		1.1	(6.9)				
Fortune		0.9	(5.6)				
Terra Nova		54.2	(341.0)				
Whiterose	Avalon/Ben Nevis	24.3	(152.6)	32.3	(1138.5)	7.17	(45.1)
Whiterose	Hibernia	3.4	(21.7)				
Outer Ridge Group							
N. Dana				13.3	(470.0)	1.80	(11.3)
S. Tempest		1.3	(8.3)				
Trave				0.8	(30.0)	0.22	(1.4)
N. Jeanne d'Arc Group							
Adolphus		0.3	(2.0)				
Stratigraphic Traps Group							
Beothuk		0.4	(2.6)				
Mara		3.6	(22.9)				
Whiterose				9.0	(318.0)	1.58	(10.0)
Totals		239.3	(1506)	101.9	(3597)	17.26	(109)

* Source: Canada-Newfoundland Offshore Petroleum Board
** Volumetric estimate by COGLA, all others are median values from distributions
*** Newfoundland Labrador Petroleum Directorship

STRATIGRAPHIC TRAPS GROUP

In all petroleum basins, a portion of the trapped hydrocarbons occurs in stratigraphic traps. Where few or no discoveries have yet been made, it is difficult to estimate what the potential of a given basin might be. D. Klemme (pers. comm.) has attempted to classify basins by their structural type and relate basin type to the nature of hydrocarbon occurrences. For strongly structured basins, such as the Jeanne d'Arc, he estimates that as much as 15 per cent of the total endowment should occur in stratigraphic plays. This analysis has used that assumption. Three types of stratigraphic plays have been considered in the analysis: 1) the basin margin pinchout of the Jeanne d'Arc sandstone; 2) the Lower Cretaceous subcrop of the reservoir sandstone at the Cretaceous unconformities; and 3) shale enclosed sandstone that occurs as channel fill or marine fans in the Upper Cretaceous and lower Tertiary fill of the basin.

Endowment

The total endowment estimated for the Stratigraphic Traps Group is 300 to 1000 million barrels (48–159 10^6m^3) of technically recoverable oil. Because of the possibility of any particular reservoir acting as a major collector for hydrocarbons, the low probability part of the distribution has a very large potential value.

Discovered hydrocarbons include two oil finds amounting to 25.5 million barrels (4 10^6m^3), and one gas discovery with 318 BCF (9 10^9m^3) of gas and 10 million barrels (1.6 10^6m^3) of associated natural gas liquids (Table 2).

The estimate of the remaining potential is 275 to 975 million barrels (44–155 10^6m^3) of technically recoverable oil. No estimate of expected individual pool sizes was attempted.

COMPARISON WITH PREVIOUS ESTIMATES

The last estimates of oil and gas resources for the Jeanne d'Arc Basin were included in GSC Paper 83-31, *Oil and Natural Gas Resources of Canada* (Procter et al., 1984). There, reported under "East Newfoundland Shelf", the oil endowment was estimated to range from a high confidence (95% probability) of 2.9 billion barrels to 17 billion barrels (0.46–2.7 10^9m^3) at a speculative level (5%). The average expectation was 8.9 billion barrels (1.41 10^9m^3). Comparable values contained in the current report would be: high confidence of 2.3 billion barrels (0.37 10^9m^3), speculative level of 8.6 billion barrels (1.37 10^9m^3), and an average value of 4.7 billion barrels (0.75 10^9m^3). At the time of the previous estimates, the Hibernia field reserves were estimated to be slightly more than one billion barrels (0.16 10^9m^3). Since then, the reserves at Hibernia have been substantially revised downward; several of the larger targets then known to exist have been tested, with mixed results; the amount and quality of reflection seismic has increased substantially; and a significantly better understanding of the geological framework and better play definition has been achieved. Each of these elements has led to the substantial reduction in estimated quantities of oil and gas in the basin as shown by the estimates contained in this report.

SUMMARY AND CONCLUSIONS

Exploration to date in the Jeanne d'Arc Basin and environs has been highly successful. Drilling of about 40 exploratory wells has resulted in the discovery of 21 oil and 11 gas pools in 17 fields. These include the giant Hibernia discovery, with reserves of about 670 million barrels (106 10^6m^3), as well as Terra Nova, with major field status and about 350 million barrels (56 10^6m^3) of oil. The two play groups that contain these discoveries, Trans-Basin Fault Trend and Basin Margins, have an exploration success rate of about 40 per cent — remarkable for a frontier basin. Discoveries and potential for the five play groups are summarized in Table 3. Discoveries to date total 1506 million barrels (240 10^6m^3) of oil; 3597 BCF (102 10^6m^3) of natural gas; and 109 million barrels (17 10^6m^3) of natural gas liquids (all median values). In addition, it is estimated that the basin contains undiscovered oil resources of between 2.1 and 3.6 billion barrels (0.33–0.57 10^9m^3) (50 per cent confidence range) with an average expectation of 3.0 billion barrels (0.48 10^9m^3).

TABLE 3

Summary of expected values of discovered oil resources and potential listed by exploration play groups in the Jeanne d'Arc Basin

Play Group	Oil 10^9 bbl (10^9m^3) Discovered	Potential
Trans-Basin Fault Trend	0.943 (0.150)	0.903 (0.144)
Basin Margins	0.528 (0.084)	1.056 (0.168)
Outer Ridge	0.008 (0.001)	0.294 (0.047)
North Jeanne d'Arc Basin	0.002 (0.000)	0.079 (0.013)
Stratigraphic Traps	0.026 (0.004)	0.653 (0.014)

To put the results of the current analysis in a more useful perspective, focusing on the primary area of interest, the estimates of oil endowment for the four structurally controlled play groups (i.e., excluding those of the stratigraphic play group) are given in Figure 50. The endowment values, ranging from 3.0 to 4.3 billion barrels (0.48–0.68 10^9m^3), represent the resources associated with the plays that have been the main focus of exploration to date. These plays are expected to contain the primary targets in the next phase of exploration. The distribution of pool sizes in the structural plays (Fig. 50) is of greatest concern as it affords a measure of the continued potential that this basin has in terms of commercial, attractive prospects for future drilling. The figure shows a highly concentrated oil resource with more than 40 per cent of

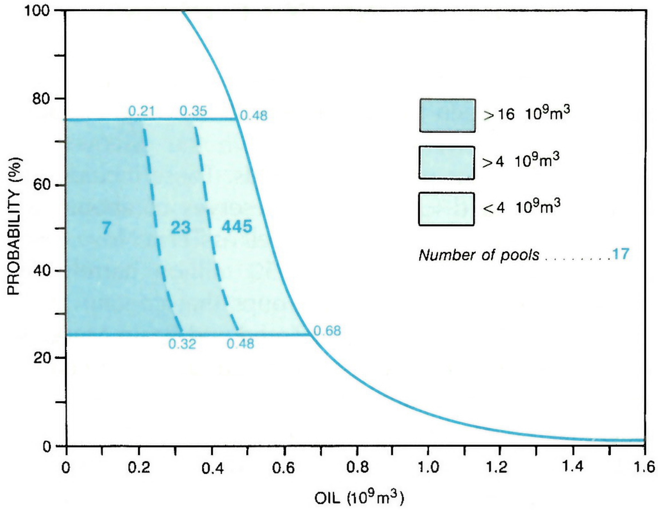

Figure 50. Distribution of estimates of the total endowment of the structural plays, illustrating the numbers and portions of the endowment expected to occur in pools of specified class sizes.

the total oil predicted to occur in only seven pools, each greater than 100 million barrels (16 10^6m^3). Five of these have already been discovered. The next size class, which includes pools between 25 and 100 million barrels (4–16 10^6m^3), is estimated to contain about one billion barrels located in 23 pools, three of which have already been found. Note that the two size classes greater than 25 million barrels are estimated to contain about two thirds of the oil associated with the structural plays in only 30 pools. The remaining one third of the resource is thought to occur in more than 400 pools. Targets that could contain the larger of the undiscovered pools, certainly those in the two size classes greater than 25 million barrels (4 10^6m^3), can be seen with existing seismic coverage.

In conclusion, the following points are considered appropriate, on the basis of the current analysis of the oil and gas resources of the Jeanne d'Arc Basin:

1. Although the present estimates of oil endowment for the basin are significantly less than those of 1983 (Procter et al., 1984), the basin is still considered rich and highly prospective.

2. The remaining potential, averaging about 3.0 billion barrels (0.48 10^9m^3), especially that part predicted to occur in two pools greater than 100 million barrels (16 10^6m^3) and in 20 pools greater than 25 million barrels (4 10^6m^3), is sufficient for exploration in the basin to be continued.

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