



Oil and Gas Report - February, 2008

Petroleum Development



Department of Natural Resources

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Offshore Newfoundland and Labrador

Land Management

Newfoundland and Labrador is located on the eastern edge of North America and is home to numerous sedimentary basins with hydrocarbon potential (Figure 1 - page 2). About 4 million hectares are currently held under licence in the offshore area. Approximately 1 million hectares are located offshore western Newfoundland and 3 million off the east coast (Figure 2a - page 4). Additionally, exploration licences were issued in July 2004 for approximately 2.5 million hectares in the Laurentian Basin south of St. Pierre and Miquelon.

There are currently \$818 million in work expenditure commitments outstanding on successful bids. Further, an additional \$19.5 million was negotiated with the Laurentian Basin licence holders. These licences resulted from negotiated agreements with former federal permit holders to convert the federal permits in the Newfoundland and Labrador portion of the Laurentian Basin into new Exploration Licenses (ELs).

About 4 million hectares are currently held under licence in the offshore area

The Canada Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) offered three separate Calls for Bids in 2006. These calls closed in November 2006 and resulted in successful bids for six parcels comprising a total of 604,647 hectares. Three of these are located in the Jeanne d'Arc Basin and the remaining three are located in the Western Newfoundland and Labrador offshore region. A total of \$32.35 million in work commitments were received. Successful bidders included Husky, Norsk Hydro, NWest Energy and B.G. Capital. Six exploration licenses were issued to the successful Bidders on January 15, 2007. The Jeanne d'Arc Basin parcels (76,419 hectares) went for a combined total of \$31,400,000. At \$410.89 per hectare, this represents the second highest dollars per hectare total since 1995 (\$3000.00/hectare).

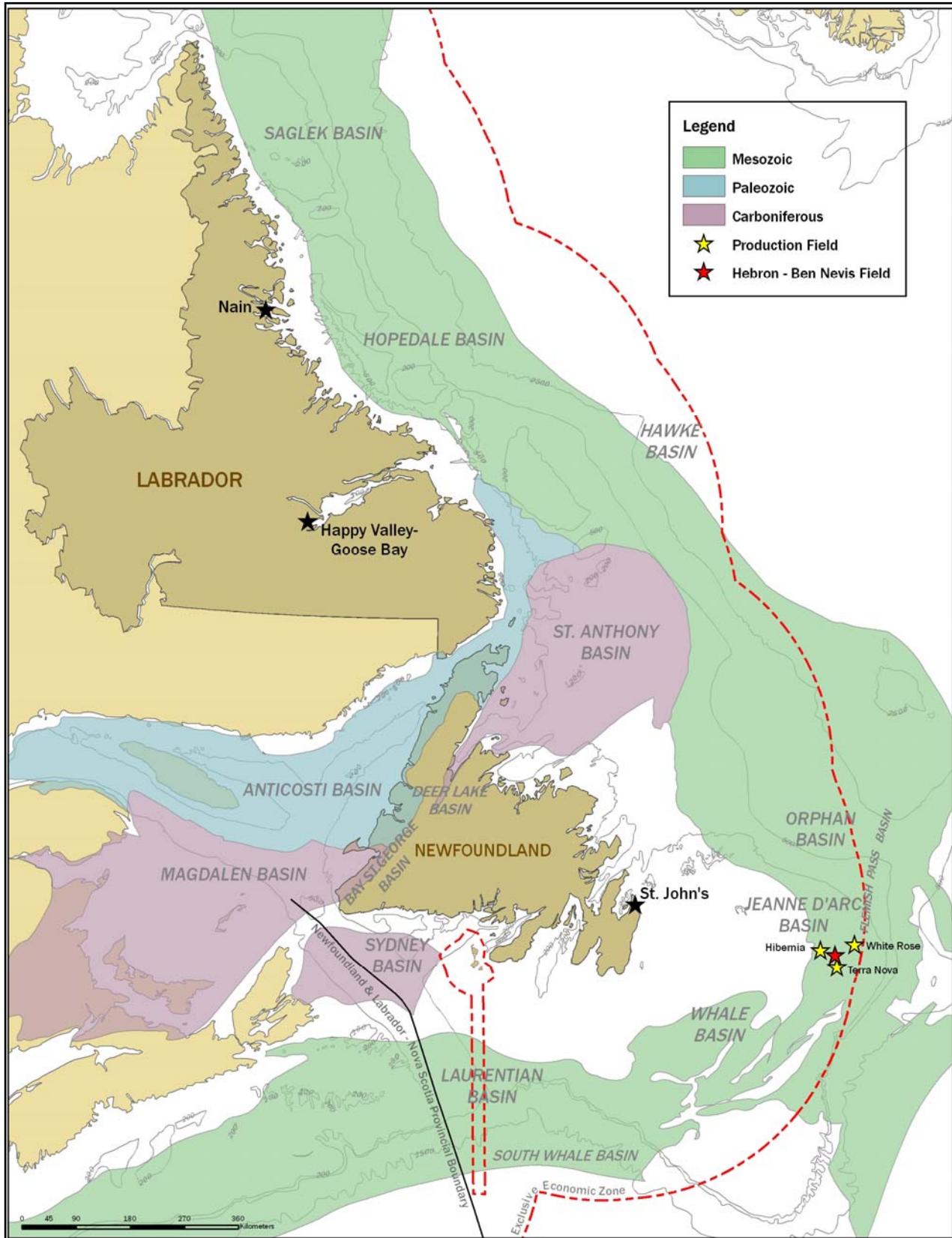
The C-NLOPB offered two separate Calls for Bids in May 2007. Call NL07-1 was for one parcel located offshore Western Newfoundland. This call closed on November 30, 2007 and a successful bid was received for that parcel in the amount of \$1,521,000. As a result, EL-1105 was issued to Corridor Resources Inc. effective January 15, 2008.

Call for Bids NL07-2 is for four parcels located offshore Labrador (Figure 2a - page 4). This Call closes on August 1, 2008. The C-NLOPB is conducting Strategic Environmental Assessments for the parcel areas offered in NL07-2.

In November 2007, the C-NLOPB issued two new Production Licences (PL-1007 and PL-1008) to Husky Oil Operations Limited (72.5%) and Petro-Canada (27.5%) for the White Rose field.

* Unless otherwise stated, all quotes are in Canadian dollars.

Figure 1 - Sedimentary Basins of Atlantic Canada



Exploration and Delineation Activity

Since the first well in 1966 to December 31, 2007, 328 wells have been spudded and in excess of 1.9 million km of seismic data have been collected in the Province's offshore area. Industry expenditures to the end of 2007, have totalled approximately \$21 billion. Exploration expenditures alone account for about \$4.8 billion by which some 2.7 billion barrels of oil and 10.2 trillion cubic feet of natural gas and 478 million barrels of natural gas liquids have been discovered.

In 2007, well site surveys were completed by Husky on their East Trave, Triton, Emerald and North Amethyst prospects in the Northern Jeanne d'Arc region totaling 675 km of 2D seismic data. Petro Canada completed their 3D seismic survey on their North Mara prospect acquiring some 20,842 CMP km. A 1030 line km electromagnetic resistivity survey was conducted by operator ExxonMobil Canada in the Orphan Basin. This is in addition to a 717 line km electromagnetic resistivity survey conducted last year in the Orphan Basin by the same operator, the first of this type of program in Canada.

*A Canadian record
for deep water
drilling was
established with the
Great Barasway
F-66 well*

There were no new offshore exploration wells spudded in 2007. The well *Chevron et al. Great Barasway F-66* was spudded in August of 2006 and completed in April 2007. This well set a Canadian record for deep water drilling in a water depth of 2338m. On January 9, 2008, ExxonMobil, a partner in the *Great Barasway* well issued an Expression of Interest for vessel services for their Orphan Basin Drilling Program, tentatively scheduled to commence between May and July 2008.

Husky Energy used the semi-submersible GSF Grand Banks to drill the three delineation wells *White Rose C-30*, its sidetrack *White Rose C-30Z* and *White Rose K-03* in 2007 while *Hibernia B-16 51Z* was the only delineation well drilled from the Hibernia platform in 2007.

Discovered Resources

To date, 23 significant discoveries have been made in the offshore area, including 5 on the Labrador Shelf and 18 on the Grand Banks. For offshore Labrador, the total discovered recoverable resource (C-NLOPB estimate; expressed at a 50% probability of occurrence) is 4.2 trillion cubic feet of natural gas and 123 million barrels of natural gas liquids (Table 1 - page 6). For the northeast Grand Banks region, total discovered recoverable resource is estimated at 2.75 billion barrels of oil, 6.0 trillion cubic feet of natural gas and 355 million barrels of natural gas liquids (Figure 2b - page 5).

Figure 2a - Newfoundland and Labrador Petroleum Rights

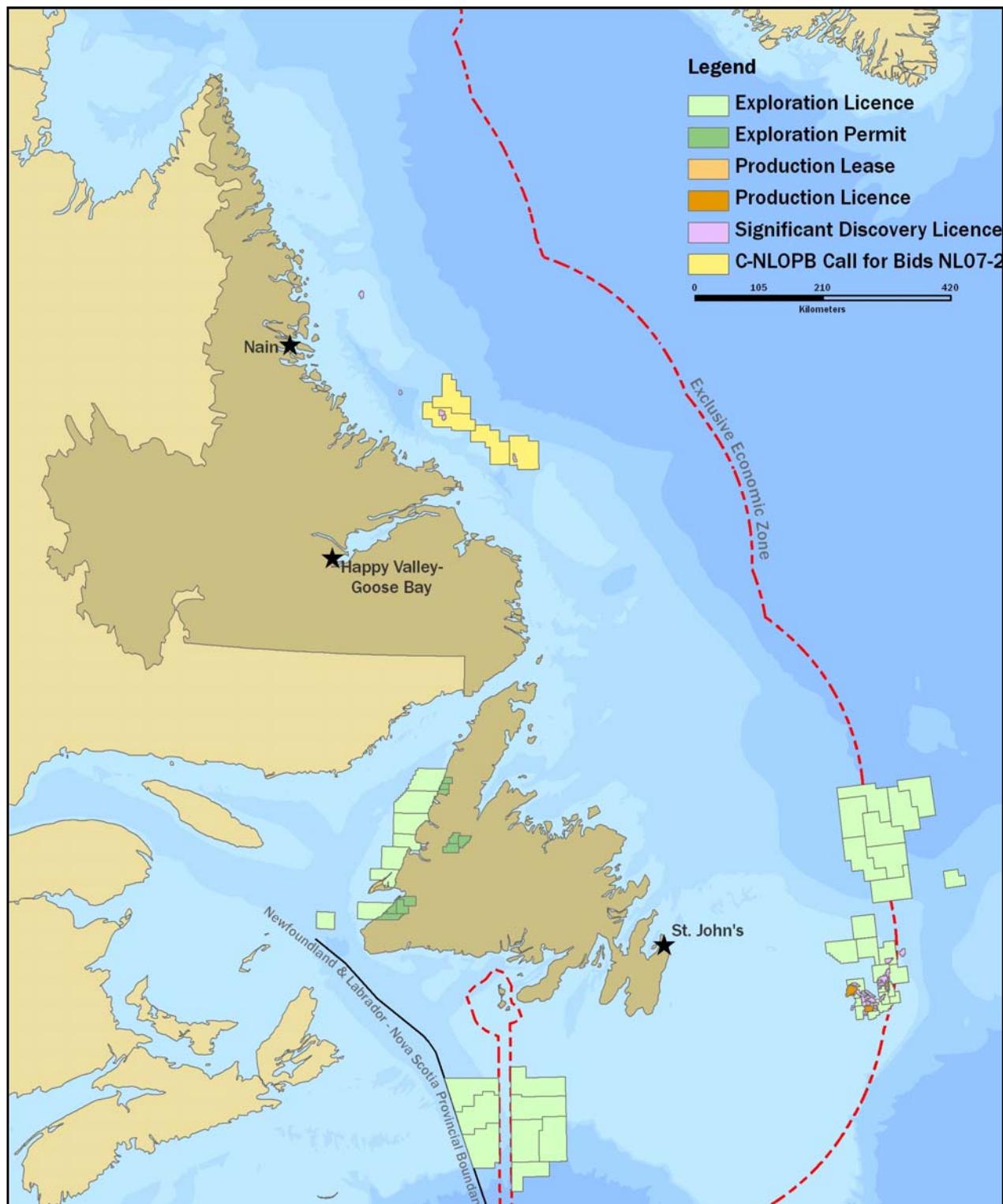


Figure 2b - North East Grand Banks Petroleum Rights

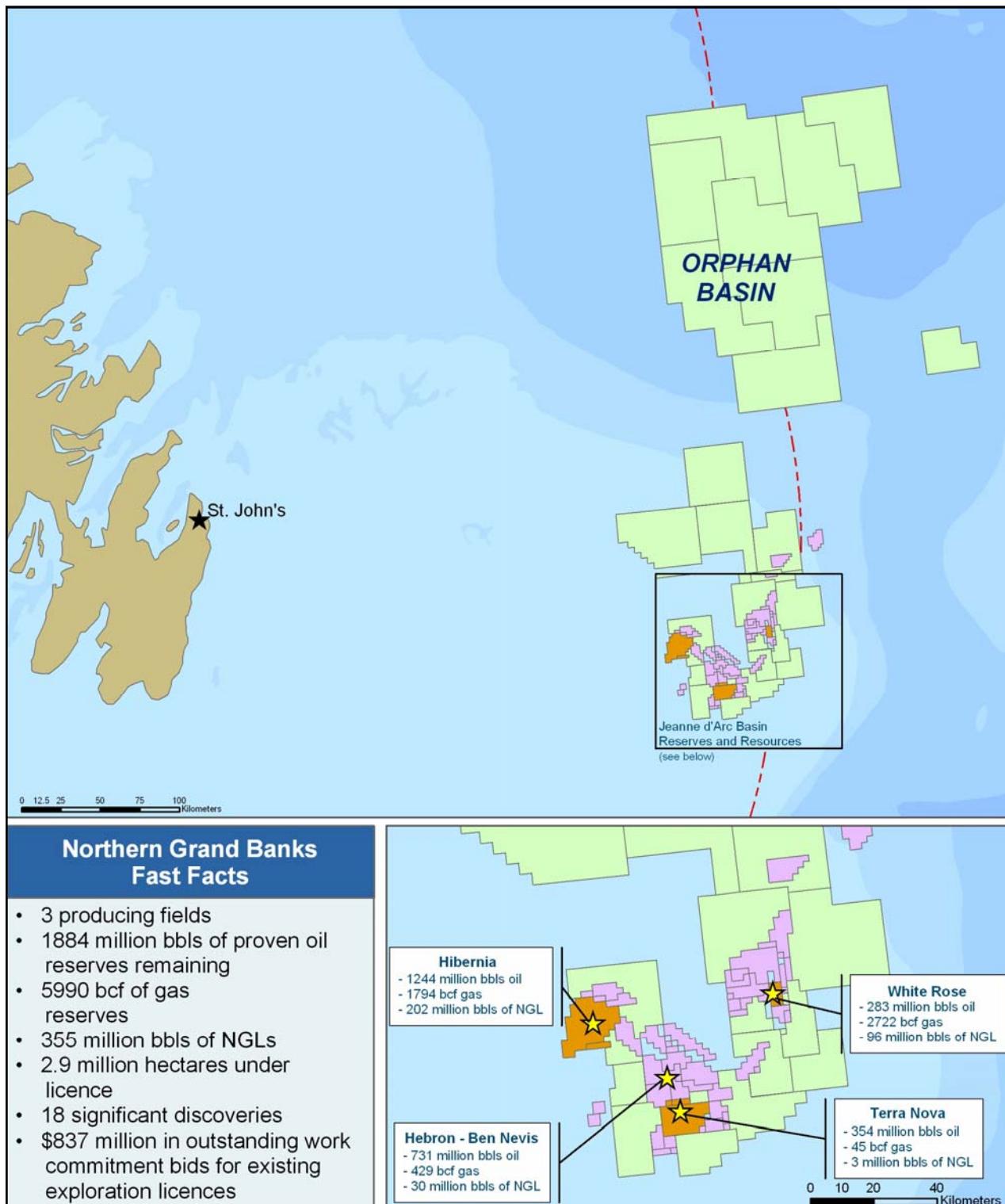


Table 1— Discovered Resources ¹— Newfoundland Offshore Area

Field Name	Oil		Gas		NGL's	
	Million m ³	MMBbls	Billion m ³	bcf	Million m ³	MMBbls
Hibernia ²	197.8	1244	50.6	1794	32.2	202
Terra Nova ²	56.3	354	1.3	45	0.5	3
White Rose ²	45	283	76.7	2722	15.3	96
Hebron	92.4	581	-	-	-	-
West Ben Nevis	5.7	36	-	-	-	-
Ben Nevis	18.1	114	12.1	429	4.7	30
North Ben Nevis	2.9	18	3.3	116	0.7	4
Springdale	2.2	14	6.7	238	-	-
Nautilus	2.1	13	-	-	-	-
Mara	3.6	23	-	-	-	-
King's Cove	1.6	10	-	-	-	-
South Tempest	1.3	8	-	-	-	-
East Rankin	1.1	7	-	-	-	-
Fortune	0.9	6	-	-	-	-
South Mara	0.6	4	4.1	144	1.2	8
North Dana	-	-	13.3	472	1.8	11
Trave	-	-	0.8	30	0.2	1
West Bonne Bay	5.7	36	-	-	-	-
Sub Total (Grand Banks)	437.3	2751	168.9	5990	56.6	355
North Bjarni	-	-	63.3	2247	13.1	82
Gudrid	-	-	26.0	924	1.0	6
Bjarni	-	-	24.3	863	5.0	31
Hopedale	-	-	3.0	105	0.4	2
Snorri	-	-	3.0	105	0.4	2
Sub Total (Labrador Shelf)	-	-	119.6	4244	19.9	123
Total	437.3	2751	288.5	10234	76.5	478

1 "Resources" are volumes of hydrocarbons, expressed at 50% probability of occurrence, assessed to be technically recoverable that have not been delineated and have unknown economic viability.

2 "Reserves" are volumes of hydrocarbons proven by drilling, testing and interpretation of geological, geophysical and engineering data, that are considered to be recoverable using current technology and under present and anticipated economic conditions.

Note: Table 1 reflects initial resource estimates with revisions as appropriate and does not include produced oil and natural gas liquid volumes.

Source: C-NLOPB

Hibernia Field

The Hibernia field, discovered in 1979, is located about 315 kilometres east southeast of St.



Hibernia GBS

John's in 80 metres of water (Figure 2b - page 5). A fixed production platform, consisting of a gravity-based structure (GBS) and topsides drilling and production facilities, has been installed to produce the field. The GBS and one of the five topsides super modules were built at Bull Arm, NL, and the four other super modules were fabricated in Korea and Italy before being transported to Bull Arm for assembly. The platform is 224 metres tall, weighs 1.2 million tonnes and can store 1.3 million barrels of oil. The crude is transported to shore by three purpose built shuttle tankers, each with 850,000 barrel storage capacity. Since October 3rd, 1998, shipments of oil from Hibernia have been offloaded at the purpose built transshipment facility at Whiffen Head, Placentia Bay, NL.

Hibernia Production

The Hibernia Project recently celebrated 10 years of production as first oil occurred on November 17th, 1997, at 1:40 p.m. The first tanker load of crude oil was off-loaded in late December, 1997. Hibernia field development was based on recoverable oil reserves of 520 million barrels and an average annual oil production rate (APR) of 110,000 barrels of oil per day (bopd). In November 1997, Hibernia Management Development Corporation (HMDC) announced that it increased its estimate of Hibernia recoverable reserves from 615 to 750 million barrels and obtained an APR of 135,000 bopd. Further increases in the APR have been granted, with the latest being in 2003 when the approved rate was increased to 220,000 bopd.

Since the original Hibernia Development Plan was approved in 1986, there have been six (6) amendments. In May 2006, HMDC on behalf of the partnership, filed an application for a proposed depletion scheme for the Hibernia South area, as well as a central fault block. On December 19, 2006 the C-NLOPB issued Decision Report 2006.02, respecting an Amendment to the Hibernia Development Plan. On January 17, 2007, the provincial Minister of Natural Resources announced that the decision had not been approved noting that "There are too many important unanswered questions in the application as put forward by HMDC." The Minister concluded that she is encouraged by the commitment to develop Hibernia South and looks forward to working with the project owners to resolve the Province's concerns. The latest C-NLOPB recoverable reserve estimates for Hibernia include 1.244 billion barrels of oil, 1.794 tcf of natural gas, and 202 million barrels of natural gas liquids with upside potential of 1.9 billion barrels.

These estimates were issued on June 1, 2006. Further reserve changes are likely as development and delineation drilling continues, new reservoir data is analyzed and improvements in recovery technologies advance. During 2007, there were a total of 28 oil producers, 17 water injectors and 6 gas injectors active in the Hibernia Field including the Hibernia and Ben Nevis/Avalon reservoirs (Figure 4b - page 9). The field averaged 134,836 bopd during 2007 with cumulative production of 569.9 million barrels to December 31, 2007.

Record Setting Wells

Hibernia is breaking new ground in directional drilling. The development wells are being directionally drilled from two rigs on the GBS into the Hibernia Sandstone which lies at a depth of about 3800 metres and the Ben Nevis/Avalon Sandstone at about 2400 metres. Since 1998, Hibernia has continued to break its own records. In 2004 the *B-16 36* well intercepted the Hibernia Sands at a depth of 3960 metres with a horizontal displacement of 7232 metres, establishing a world record for horizontal displacement at such a depth. In 2005, Hibernia drilled and completed a dual injection well, *Hibernia B-16 50*, which penetrated two targets through two different reservoirs. This strategy was pursued again in 2007 with the *B-16 55* well. The Hibernia well construction team has established itself as a world leader in extended reach drilling, and continues to prove that it can provide creative technical solutions that are required to optimize resource recovery. This experience will be critical as the team attempts to explore and develop the southern region of the field.

Figure 4a - Hibernia Field Geological Cross Section

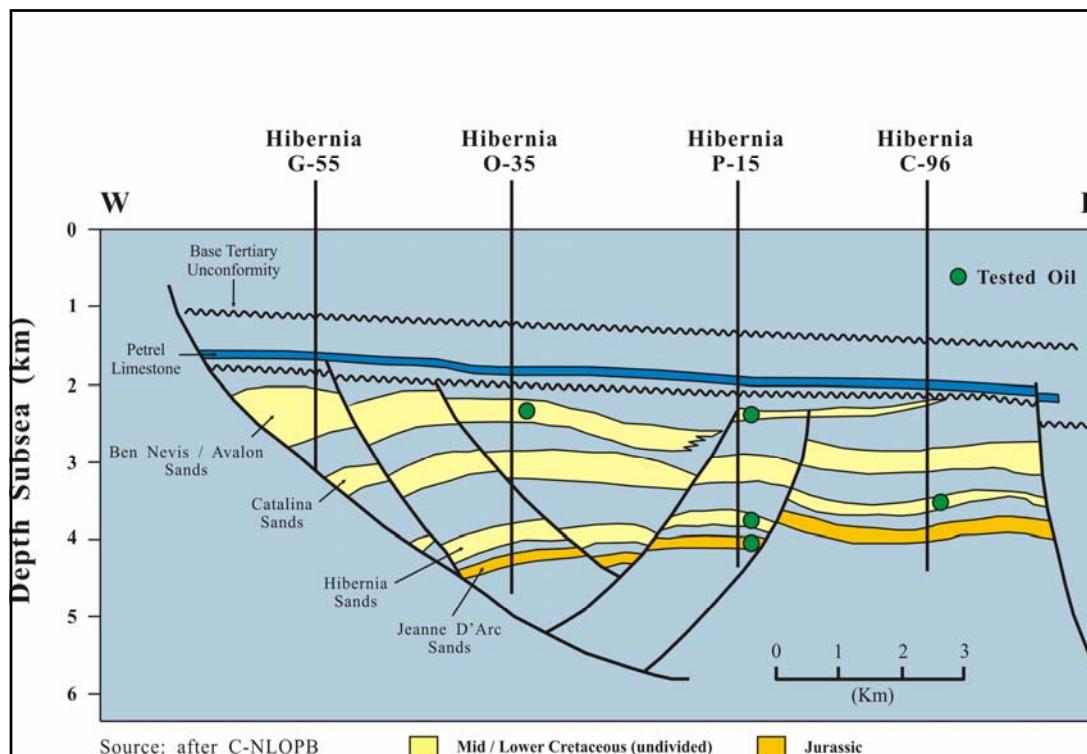
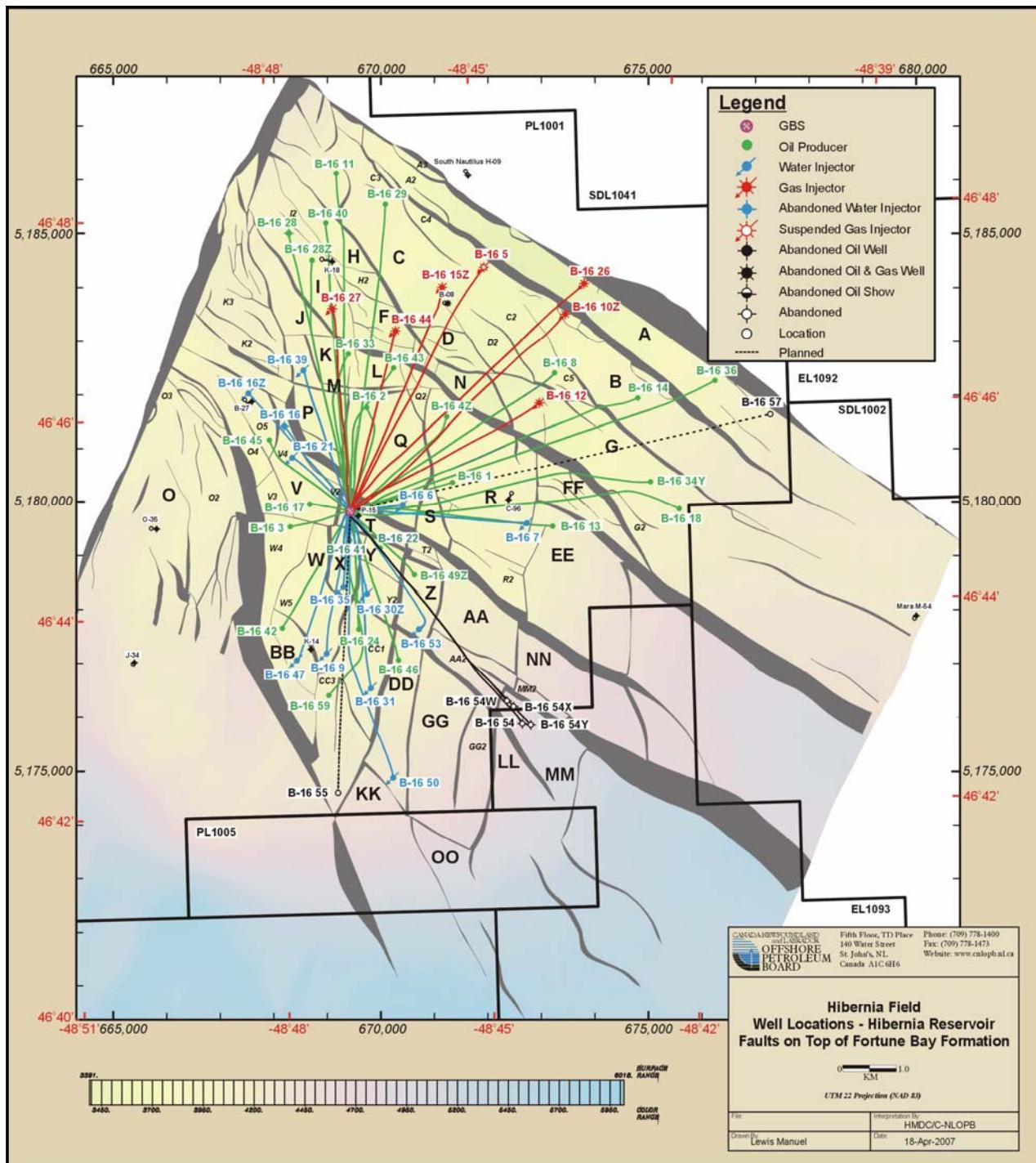


Figure 4b - Structure Map of Hibernia Reservoir



Terra Nova Field

The Terra Nova field was discovered by Petro-Canada in 1984 about 35 km southeast of Hibernia, in 90 metres of water. The *Terra Nova K-08* discovery well flow-tested 10,000 barrels of oil per day from the Jurassic Jeanne d'Arc Sands. Five successful delineation wells tested at rates ranging from 5,000 to 25,000 bopd. On August 4th, 2001, the Floating Production Storage and Offloading (FPSO) vessel arrived at the field, and first-oil flowed on January 20th, 2002.



Figure 5 - Terra Nova Floating Production Storage and Offloading Facility

Geologically, the field consists of three fault-defined blocks designated as the Graben, East Flank and Far East blocks (Figure 7a - page 11). The proponents have indicated the most likely reserves for the Graben and East Flank are 400 million barrels recoverable and the far East Central area containing about 40 million barrels of recoverable oil. The latest C-NLOPB recoverable reserves estimates for Terra Nova are 354 million barrels of oil, 45 bcf gas and 3 million barrels of gas liquids.



Terra Nova FPSO

The original plan contemplated producing oil from the Graben and East Flank for the first six years at an average of 115,000 barrels of oil per day. However, based on the productive capacity of the wells, the C-NLOPB has allowed production rates to be increased to 180,000 barrels per day. The development plan contemplates 14 producing wells and 10 injection wells in the Graben and East Flank with individual wells expected to produce in excess of 20,000 bopd. The expected life of the field is about 14 years but it could be extended depending on drilling results and oil prices.

In 2007, active wells included 15 oil producers, 8 water injectors and 3 gas injectors. Development drilling in the Terra Nova field concluded in 2007. Petro Canada re-entered *Terra Nova L-98 6* on February 17, 2007 to abandon the perforated zones and commenced the *Terra Nova L-98 6Z* sidetrack well on March 29.

This was the last well to be drilled in a six-year, 27-well drilling program in the Terra Nova oilfield. Well work overs were conducted on the *G-90 3*, *G-90 54* and *L-98 2* wells.

The field averaged 116,268 bopd during 2007 with production for the year of 42.4 million barrels. Cumulative field production to the end of 2007 was 219.8 million barrels.

Figure 7a - Terra Nova Field Geological Cross Section

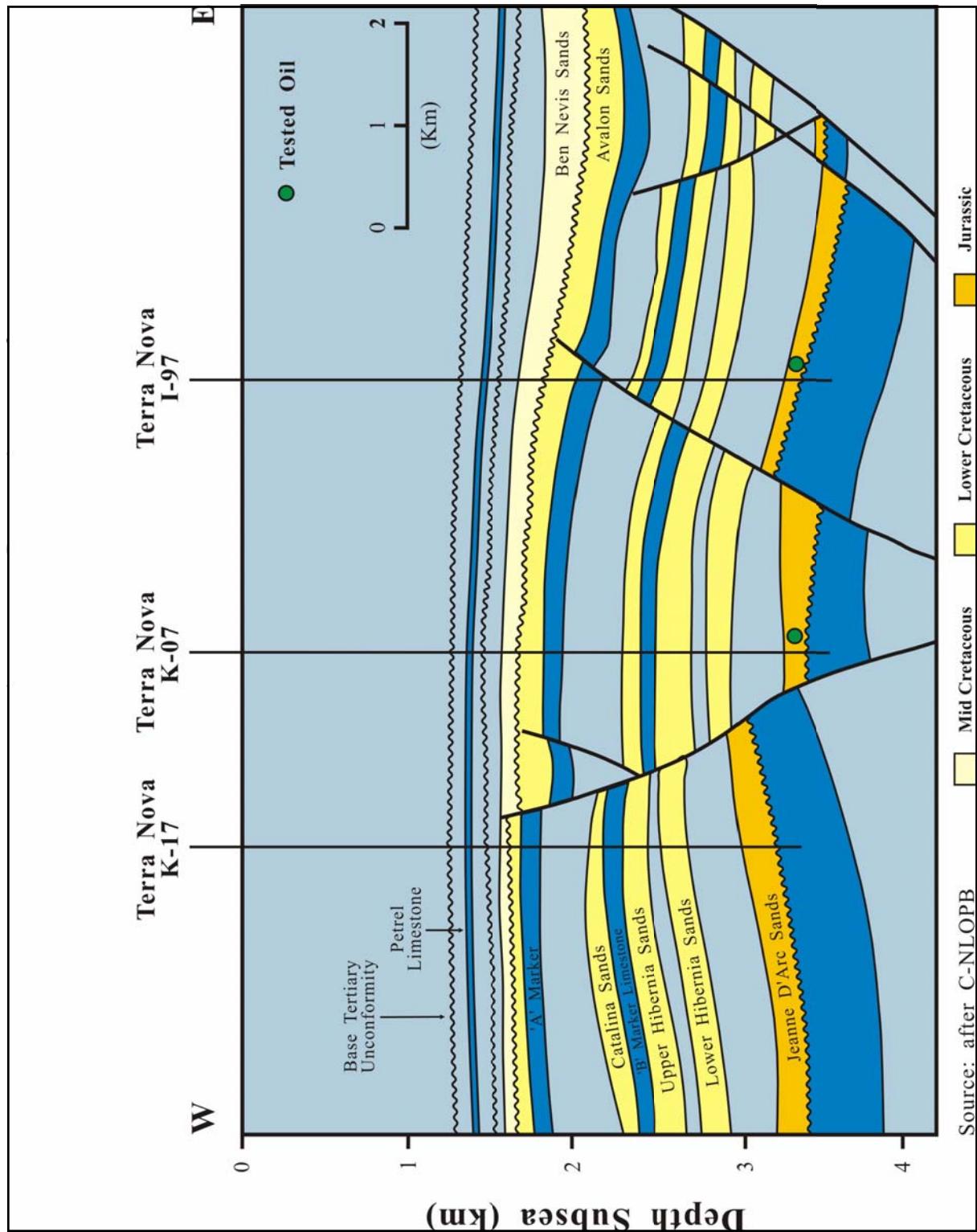
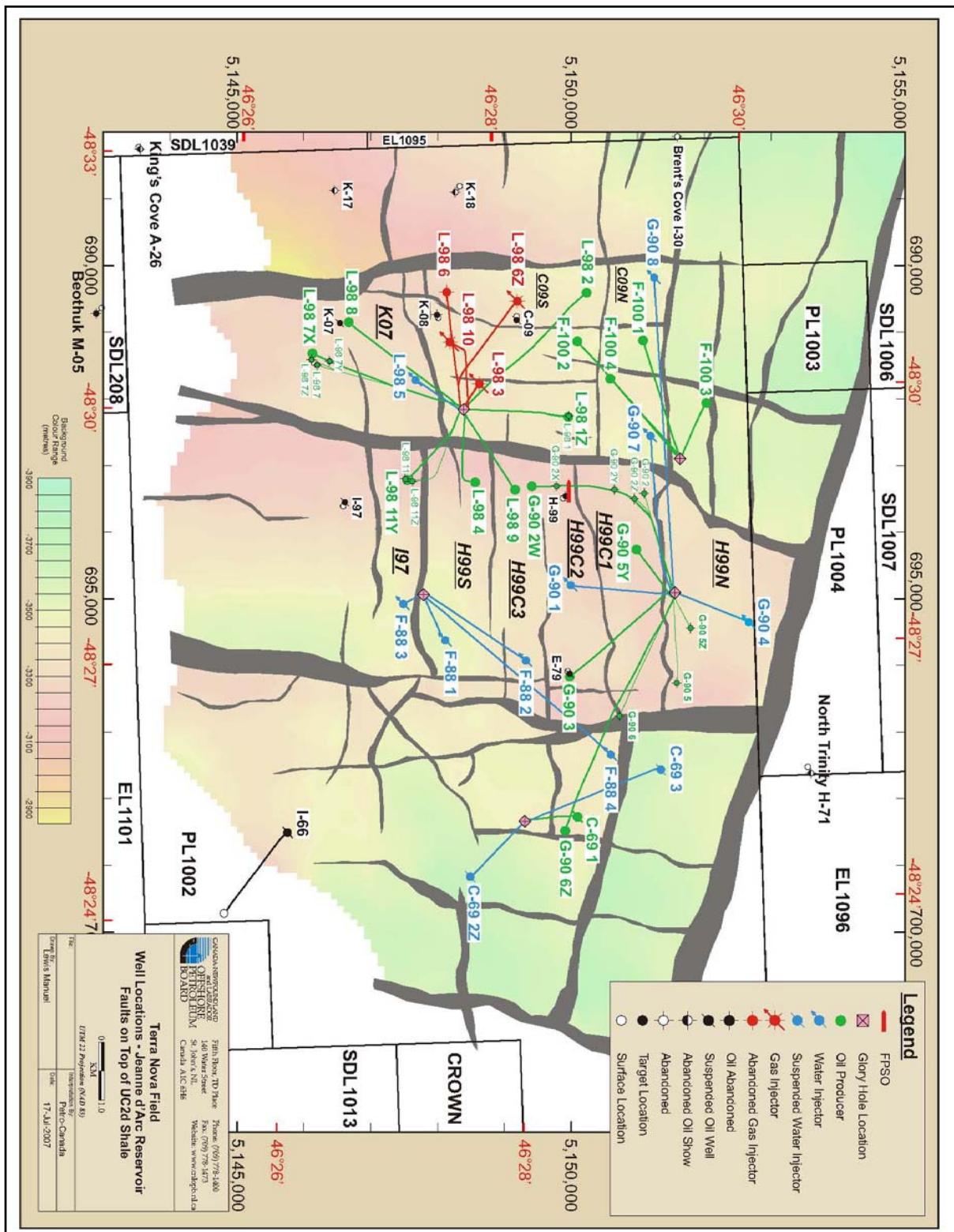


Figure 7b - Structure Map of Jeanne d'Arc Reservoir



White Rose Field

In 1984, the *White Rose N-22* discovery well tested at 900 bopd, 25 million cubic feet per day of natural gas and 840 bopd of condensate. During 1987-88, the *White Rose E-09* delineation well encountered 94 metres of net oil pay and tested at 5,000 bopd and 4 million cubic feet per day of natural gas from the Avalon Sandstone. In addition, the *J-49* delineation well flowed oil at 3,000 bopd and gas at 10 million cubic feet per day and the *L-61* delineation well tested gas at 24 million cubic feet per day and condensate at 436 bopd.

Three appraisal wells were drilled at White Rose during 1999 which resulted in the C-NLOPB increasing its resource estimates for the field from 178 to 283 million barrels of oil, 1.51 tcf to 2.7 tcf of natural gas, and from 58 to 96 million barrels of natural gas liquids. The *White Rose H-20* delineation well drilled in May-June 2000, encountered less pay than expected and prompted Husky to reduce its recoverable oil estimate for the South White Rose pool from 255 million to 230 million barrels.



Sea Rose FPSO

On January 15th, 2001, Husky submitted a development plan application proposing White Rose development by FPSO. On March 28th, 2002, Husky and its partner Petro-Canada announced their decision to proceed with the project and production began from the White Rose field November 12, 2005.

The “Sea Rose” FPSO has a storage capacity of 940,000 barrels oil and as of April 2, 2007 approval was received from the C-NLOPB to increase the production rate to 137,000 bopd. The ice strengthened double hull was completed in South Korea and final fabrication, installation and commissioning of topsides was completed at the Cow Head Fabrication Facility in Marystow, NL. The topsides consist of modules that process and treat oil, gas and water, generate power, inject water into the producing reservoir and reinject gas into the North pool for gas conservation. When commissioning was completed on November 12th, 2005, first oil was processed on the Sea Rose.

Husky has begun front end engineering design studies to tie back satellite reservoirs to the Sea Rose FPSO. The complete scope of these studies includes White Rose South Extension, North Amethyst and West White Rose Pools.

A new glory hole was completed on August 3, 2007 by the vessel Vasco de Gama in advance of the application for development of the North Amethyst Field located south east of the Sea Rose location. This part of the field is estimated by Husky to hold 66 to 120 million barrels of oil and 120-220 bcf of natural gas.

White Rose development drilling continued in 2007 using the GSF Grand Banks, with the drilling of one oil producer (*E-18 8*), one water injector (*E-18 7*, suspended at target depth), and one gas injector (*J-22 2*).

On December 17, 2007 a joint statement was issued by Husky and the Government of Newfoundland and Labrador whereby a formal agreement between Husky Energy, Petro-Canada and the Province's Energy Corporation to develop the White Rose Expansion oil fields was reached. It has been estimated that the project will require 9.6 million person hours of work over its lifetime. The companies estimate first oil from the project in the fourth quarter of 2009.

In 2007 the White Rose field produced 42.8 million barrels of oil for an average of 117,284 bopd. Cumulative field production to the end of December 31, 2007 was 77.3 million barrels.

Figure 9a - White Rose Field Geological Cross Section

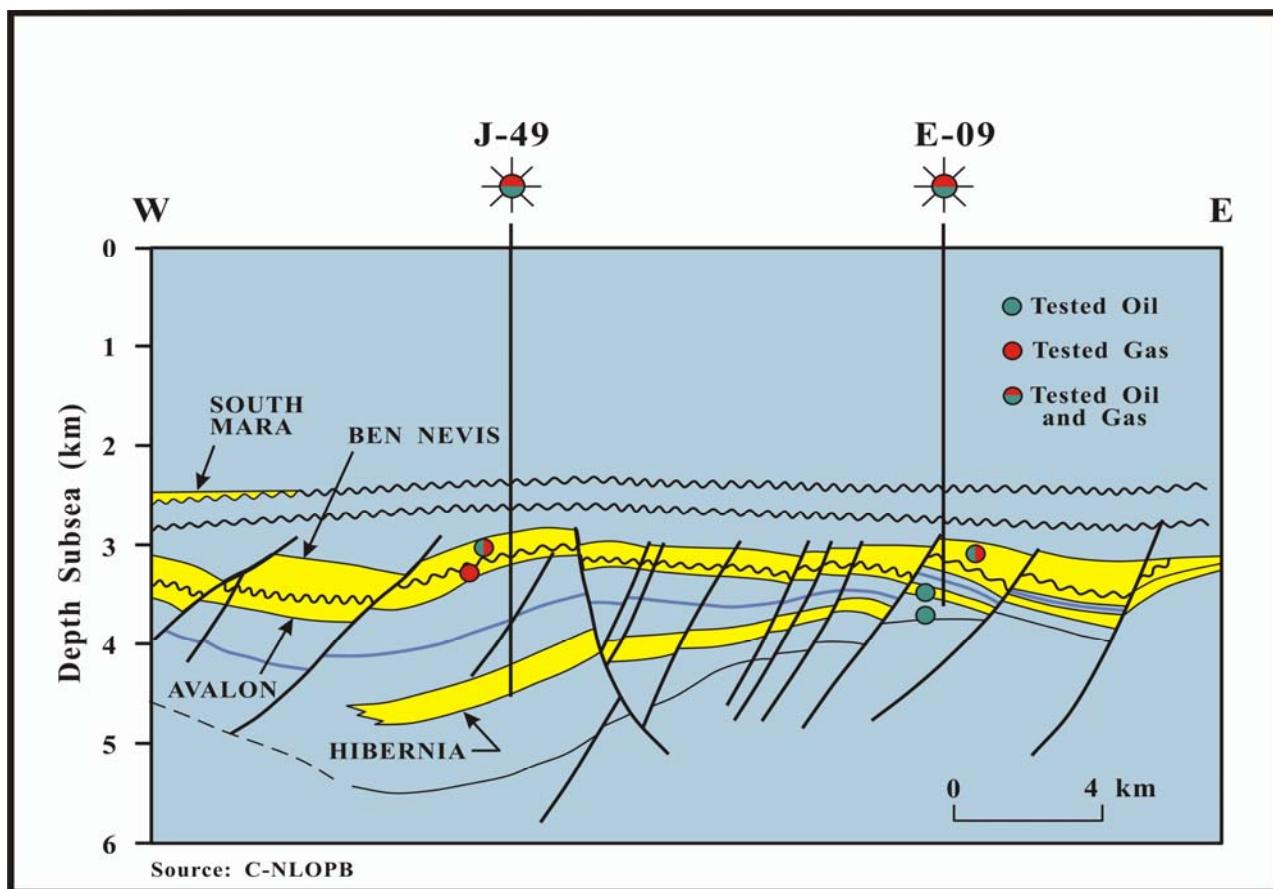
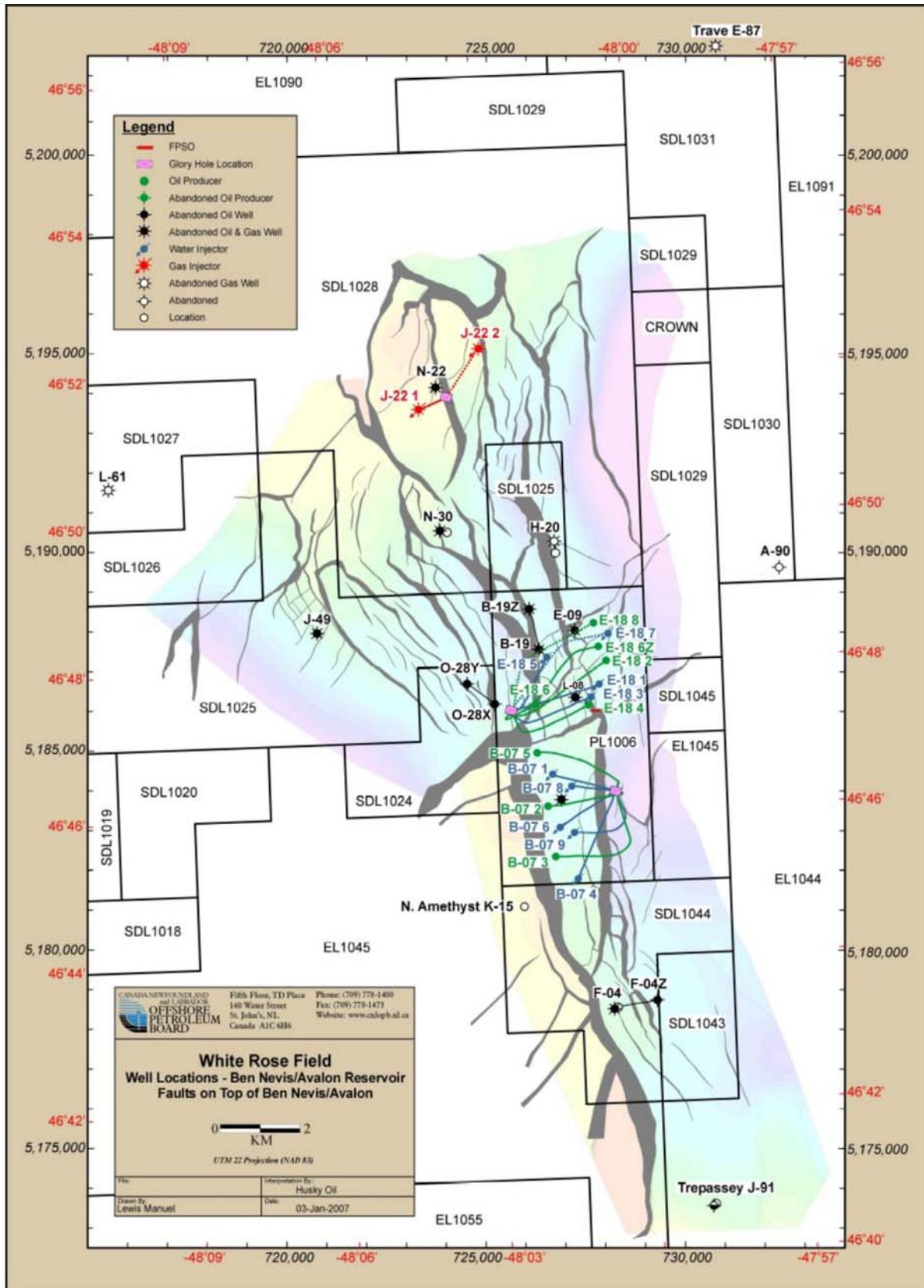


Figure 9b - Structure Map of White Rose Reservoir

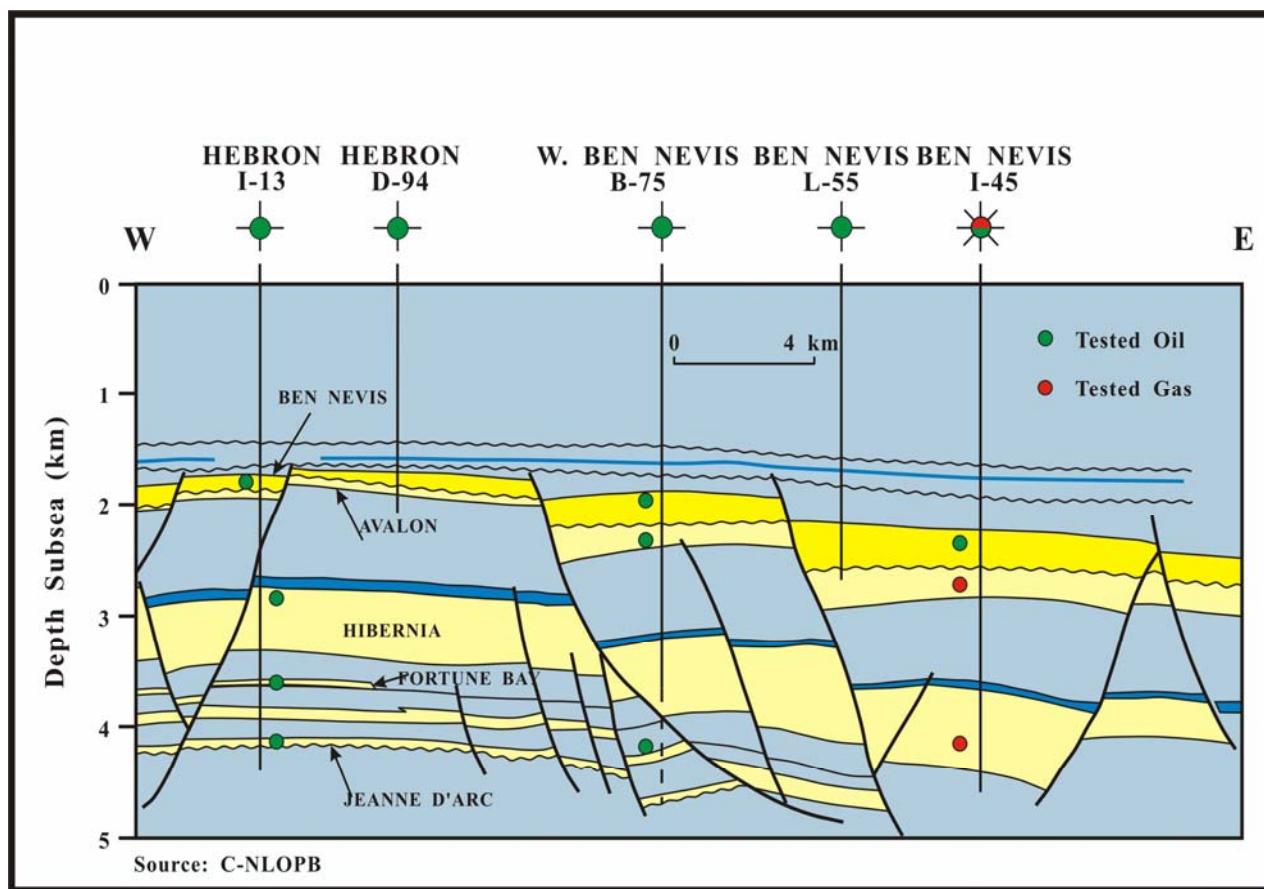


Future Petroleum Developments

Hebron / Ben Nevis Complex

The *Mobil et al Hebron I-13* discovery well, drilled in 1981 in about 94 metres of water, recovered hydrocarbons from five intervals with a combined flow rate of 9,070 bopd. The Ben Nevis field (discovered in 1980) and West Ben Nevis field (discovered in 1984) are located in fault blocks that lie to the northeast and adjacent to Hebron. During 1999, the *Hebron D-94* delineation well encountered 86 metres of net oil pay in a 92 metre interval within the Ben Nevis Sandstone. A representative flow test from the 1,842 to 1,908 metre interval recovered 21 degree API oil at a rate of 3,500 barrels per day. A second delineation well, *Chevron et al Ben Nevis L-55*, tested 1,150 bopd of 30 degree API oil from a 71.3 metre pay interval. An additional delineation well, *Hebron M-04*, drilled in the Spring of 2000 tested 2,250 bopd and 1.6 million cubic feet per day of natural gas from the Jeanne d'Arc Sandstone.

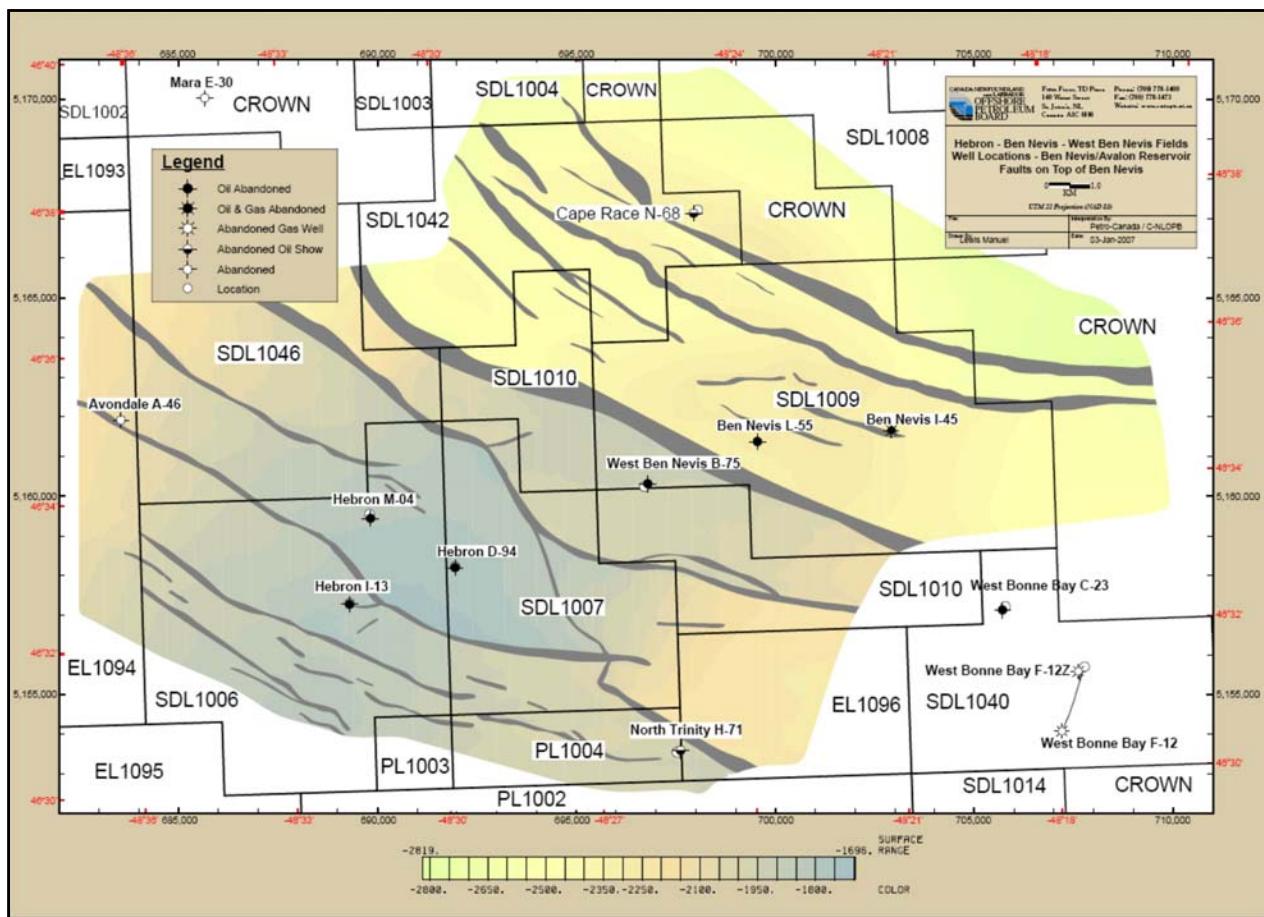
Figure 10a - Hebron/Ben Nevis Field Geological Cross Section



The latest C-NLOPB reserve estimate is 731 million barrels of oil, 429 bcf of natural gas and 30 million barrels of natural gas liquids. Because of the close proximity of the smaller Ben Nevis and West Ben Nevis fields, they would very likely be part of any Hebron development.

In August 2007, the Chevron led partnership announced they had signed a Memorandum of Understanding on fiscal and local benefits with the Government of Newfoundland and Labrador. In addition to a 4.9 per cent equity stake in the project, the province negotiated an additional 6.5 per cent royalty paid on net revenues whenever monthly average oil prices exceed \$50 (US) WTI per barrel after net royalty payout occurs. It will take several months to execute formal detailed agreements; and of course, normal project sanction processes must take place. Once the formal equity, fiscal and benefits agreements are executed, equity will be exchanged and partners will commence project activities.

Figure 10b - Structure Map of Avalon/Ben Nevis Sandstone

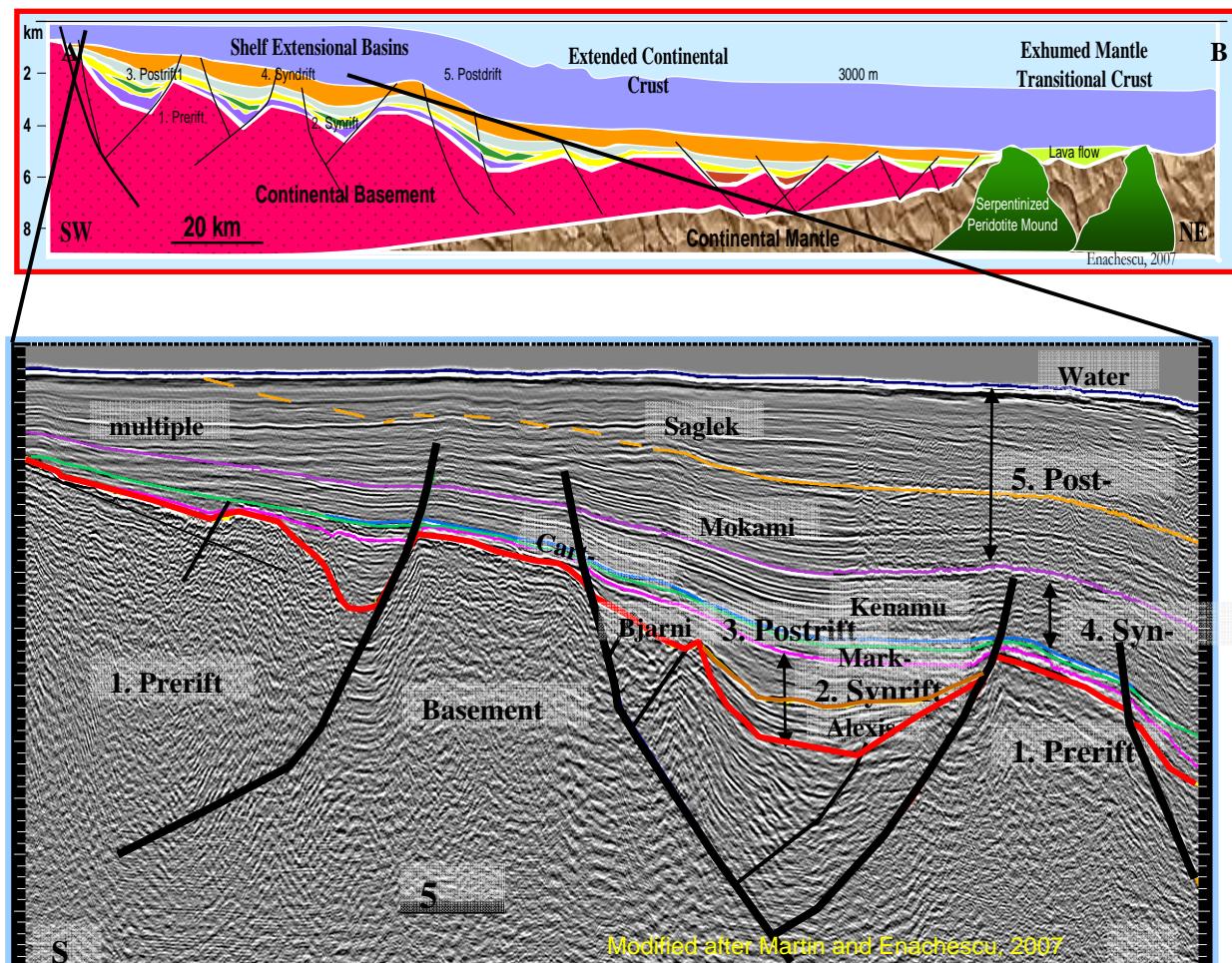


Labrador

The C-NLOPB currently estimates the Labrador offshore area holds about 4.2 tcf of discovered gas (~44% of NL offshore total) and 123 million barrels of Natural Gas Liquids (NGLs). These resources are located in five fields in the offshore Labrador Shelf region (Figure 12 - page 20). The first well drilled in this area was in 1971, with the most recent drilling occurring in 1983. There has been a total of 28 wells drilled (26 exploration and 2 delineation wells) leading to 5 Significant Discovery Licenses (SDLs) being issued yielding a 19.2% drilling success.

Over the past six years, the first seismic programs acquired offshore Labrador in more than two decades were completed. These programs have resulted in more than 37,000 line km of new 2D data being obtained. Additional data acquisition programs are planned for 2008. The new focus is to search for oil deposits in deepwater plays along the continental slope.

Figure 11 - Labrador



In August 2007, TGS-NOPEC received joint approvals from the C-NLOPB and the National Energy Board to conduct a proposed 2D seismic program in the marine area comprising Baffin Bay/Davis Strait/North Labrador Sea. The proposed program contemplates nearly 11,000 km of 2D date in the region.

These programs will help to update and strengthen the database of resource information related to this area particularly the deeper off-shelf areas where similar geological features have yielded oil seeps in the adjacent Greenland area, as well as gas finds in the Davis Strait region. This is part of a worldwide trend to explore the deep water areas which have resulted in large discoveries offshore Brazil, West Africa, Gulf of Mexico and elsewhere.

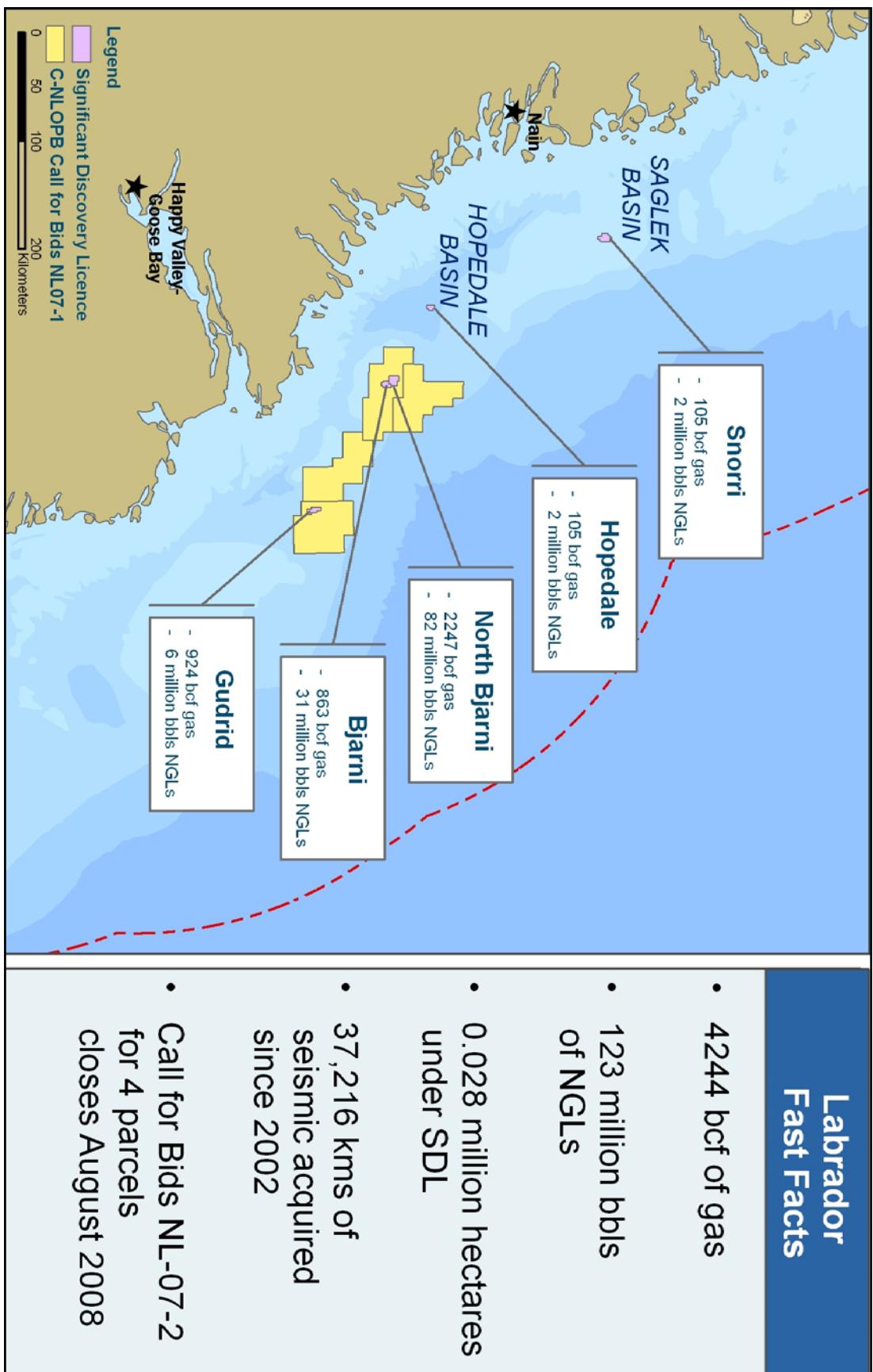
The feasibility of developing offshore Labrador's substantial gas resources has been studied by the Department of Natural Resources with the conclusion it will require certain technological advances, including improved pipeline trenching methods to protect against iceberg scour, and long distance multi-phase flow and metering technologies. Alternately, advancements in marine CNG technology may be a viable transportation method. Although development is not anticipated within the short term, improvements in technology and an increased demand for cleaner burning fuels may accelerate development of these resources. The Department is engaged in a 3 year Joint Industry Project with C-CORE, a global engineering corporation, that is focused on subsea ice risk assessment and mitigation.

Labrador Land Sale

The Canada-Newfoundland and Labrador Offshore Petroleum Board announced details of the 2007 land sale in the Newfoundland and Labrador Offshore Area. The Labrador Offshore Region will consist of four parcels that comprise a total of 939,678 hectares (Figure 12 - page 20).

Interested parties will have until 4:00 p.m. on August 1, 2008 to submit sealed bids for Call for Bids NL07-2 (Labrador Offshore Region). The Board is conducting a Strategic Environmental Assessment (SEA) for the Labrador Offshore Area to include the four parcels offered in Call for Bids NL07-2. A draft of the SEA report will be published on the Board's website for public comment when it becomes available. The Board will consider any recommendations made in the SEA Report and, where necessary, may amend the respective Call for Bids to ensure concerns are addressed.

Figure 12 - Off shore Labrador 2008 Land Sale Parcels and Significant Discoveries



Other Significant Discoveries

Twelve additional wildcat wells within the northern Grand Banks area have encountered significant oil and/or gas shows. The most significant are *Fortune G-57*, which flowed at 6,978 bopd and gas at 8.4 million cubic feet per day, and the *North Ben Nevis P-93*, which flowed at 5,000 bopd and 18 million cubic feet of natural gas per day. Further drilling is required to determine the significance of these discoveries, but several smaller fields may be developed as satellites to the stand-alone projects.

Summary Comments

Offshore Newfoundland and Labrador has moved from a purely exploration frontier to the realm of significant producer. With Hibernia, Terra Nova and White Rose contributing to production, the province can expect to produce in excess of 400,000 bopd. At the same time, a critical threshold of infrastructure and technical capability is being achieved that will accelerate development of the smaller fields and is encouraging exploration.

A great deal of seismic data has been acquired over the past several years which is being used to re-evaluate areas that have been ignored for more than 20 years. Advances in drilling and production technology are improving recovery factors and facilitating the exploitation of deep water areas such as the Flemish Pass, and the Laurentian and Orphan Basins. Recent seismic mapping and land sale results in the Orphan Basin have demonstrated there are very large undrilled features in our offshore area. Husky continued delineation drilling in the Jeanne d'Arc basin during 2007.

Drilling in the Orphan Basin commenced on August 18, 2006 and the Laurentian Basin should follow. Given the amount of acreage available and the relatively sparse drilling that has occurred, the Newfoundland and Labrador offshore area remains one of great opportunity. A large new discovery in any one of these basins will lead to rapid expansion of exploration efforts.

All of these elements combine to support a continued expansion of the Province's oil and gas industry over the next several years.

Onshore and Offshore Western Newfoundland

Petroleum interest for onshore western Newfoundland dates back approximately 140 years, when in 1867 a well was drilled on the Northern Peninsula at Parsons Pond by John Silver, a sawmill operator from Nova Scotia. Over the ensuing years, records up to 1973 indicate that at least 60 wells spread over five distinct areas: Parson 's Pond; St. Paul 's Inlet; Shoal Point; Deer Lake; and Bay St. George had been attempted, with fair to excellent hydrocarbon shows being recorded in over half of those efforts.

Sporadic production was achieved at Parsons Pond and possibly at Shoal Point during the late 1890 's and into the early 1900 's, with total production estimated at less than 10,000 barrels over a thirty year interval from 1895 to 1925.

The current round of exploration activity began during the early 1990 's, following release of geological reports favorable to hydrocarbon exploration in the region, announcement by Government of a new onshore Royalty regime and shortly thereafter in 1995, by the discovery of oil and gas by Hunt / PanCanadian on the Port au Port Peninsula. This discovery well was the first to be drilled with the benefit of seismic information.

Three Paleozoic aged sedimentary basins, the Anticosti, Bay St. George and Deer Lake (approximately 1,762,000 ha. in area) make up the onshore portion of western Newfoundland, with the Anticosti and Bay St. George basins extending out under the Gulf of St. Lawrence. The Anticosti Basin is three times larger (1,307,000 ha.) than the other two and contains rock sequences ranging in age from Lower Cambrian to Devonian. Both the Bay St. George and Deer Lake Basins contain mostly Lower Carboniferous aged rock sequences. All three basins have proven petroleum systems (Figure 1 - page 2) .

The onshore and offshore areas have received sporadic 2-D seismic coverage since the late 1960 's, with most of this taking place during the late 1980' s to early to mid 1990' s . There are currently 1056 line km of onshore data and 12,203 line km of offshore coverage in the Gulf of St. Lawrence. Onshore coverage is very sporadic and existing datasets are concentrated in the Parson 's Pond, Port au Port Peninsula, northern Bay St. George and northern Deer Lake basin regions (Figure 19 - page 33) . There are at present ten exploration permits and one production lease (regulated under the Petroleum and Natural Gas Act) active for onshore western Newfoundland. These total approximately 280,390 ha. Eight offshore exploration parcels (regulated under the Canada-Newfoundland Atlantic Accord Implementation Acts) , totaling 1,079,230 ha are presently under license in the Gulf region (Figure 13 - page 24).

There is currently only one onshore well planned for western Newfoundland in 2008. PDI Production Inc., as operator of Petroleum Lease 2002-01 on the Port au Port Peninsula have secured a rig to drill one well, with the option of two further wells, dependent on results.

Onshore to Offshore Exploration

The interest holders of offshore EL 1070 entered into a farm-in agreement with Shoal Point Energy (SPE) to drill an onshore to offshore well from Shoal Point (onshore location) into the offshore (EL 1070). SPE has not received final authorizations from the Department of Natural Resources or the Board to commence the drilling program. Final authorizations will be provided when the drilling equipment has been delivered and installed. Authorizations from both Governments is required due to the well being an onshore to offshore drilling program.

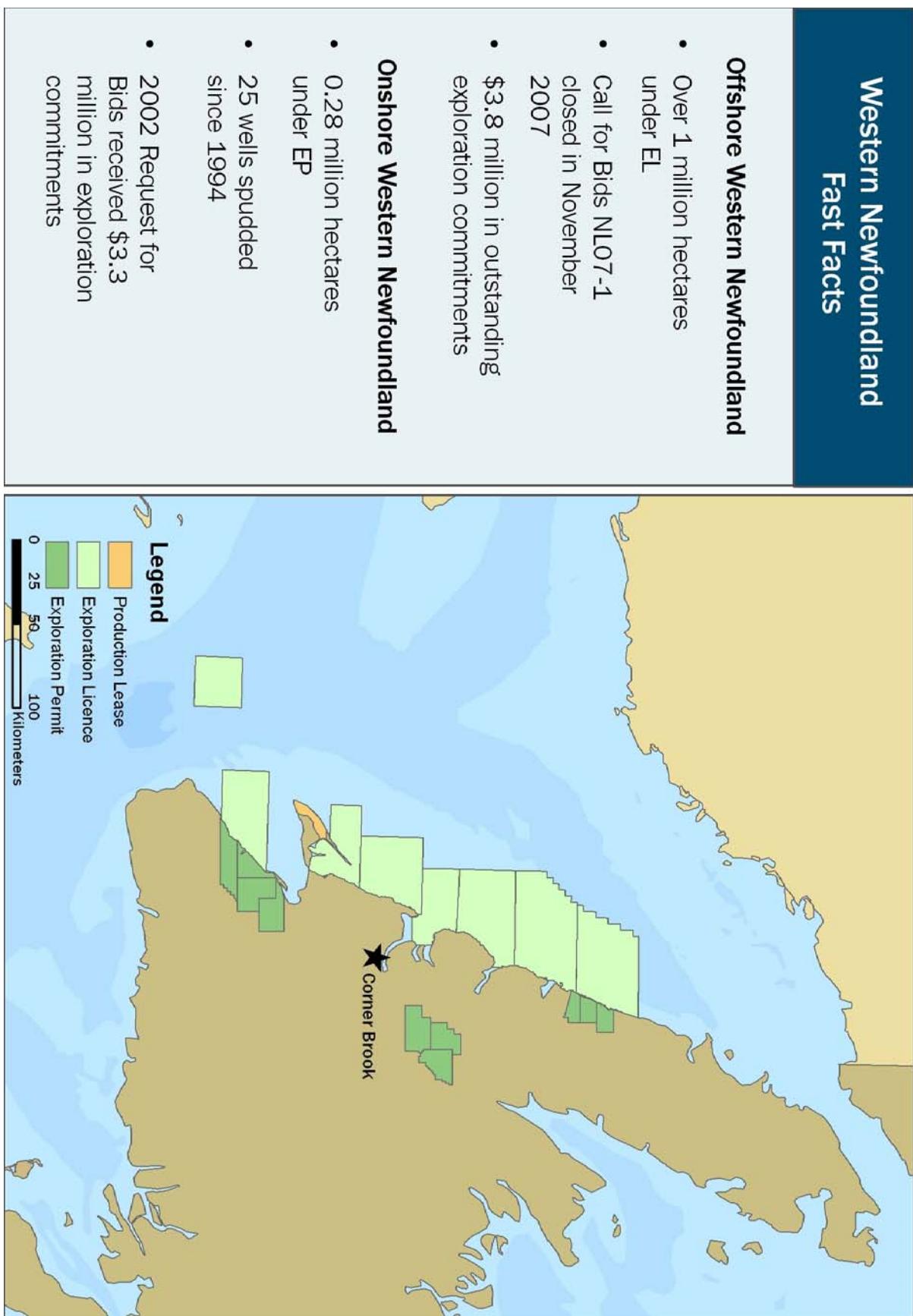
Also, Ptarmigan Resources Ltd. had entered into a farm-out agreement with Tekoil and Gas Corporation (Tekoil) to drill an onshore to offshore well from Lark Harbour (onshore location) into the offshore (EL 1069). Tekoil has received authorization from the Department of Natural Resources to spud the onshore portion of the well but final authorizations for the offshore portion will be provided when the drilling equipment has been delivered and installed. Authorizations from both Governments is required due to the well being an onshore to offshore drilling program.

Anticosti Basin Port au Port No. 1 Discovery and Follow-up Exploration

The Hunt / PanCanadian Port au Port #1 well (at Garden Hill) was spudded in September 1994 and attracted the attention of the Province and petroleum industry in the spring of 1995 when a flare from the well lit up the sky along the southwestern part of the Port au Port Peninsula. The well encountered two hydrocarbon bearing intervals within upper Aguathuna Formation dolostones, with flow rates, respectively, at 1,528 and 1,742 barrels per day of 51°API oil and 2.6 and 2.3 million cubic feet per day of natural gas, plus associated water. An extended test conducted over a nine day period on one of the intervals produced a total of 5,012 barrels of oil and 9.2 million cubic feet of gas. Analysis of test results suggested the possibility of a limited reservoir or complex geology at the location. Test results may also have been influenced by issues related to salt and paraffin build-up while testing.

In October 1999, Canadian Imperial Venture Corporation (CIVC) completed a farm-in arrangement with Hunt / PanCanadian on this project and immediately began additional flow and pressure testing. They completed a 26 km 2-D seismic survey over the area during the summer of 2000 and followed this in 2001, by submitting a development plan for the Garden Hill field.

Figure 13 - Western Newfoundland Petroleum Rights



Under Phase 1, CIVC hoped to achieve production from the original wellbore and drill a side-track well towards the northwest, targeting the up-dip portion of the Garden Hill structure. Port au Port sidetrack #1 was drilled in mid to late 2001 and failed to encounter commercial hydrocarbons in the upper Aguathuna Fm.

On April 3rd, 2002, Government issued a Production Lease to CIVC, thereby allowing them to develop the site. CIVC drilled a second sidetrack well (Port au Port sidetrack #2) towards the northeast during the summer of 2002. This well terminated in close proximity to the original PAP #1 well and upon testing flowed 195 bopd and 1.2 million cubic feet per day of natural gas with no produced water reported.

During 2003 CIVC experienced financial difficulties that affected operations at Garden Hill. Issues related to these difficulties were not resolved until the spring of 2006, when CIVC announced that pending approvals from the Department of Natural Resources and the TSX Venture Exchange, a series of linked transactions had been negotiated and signed, between CIVC, CIVC Creditor Corp., ENEGI Inc., PDI Production Inc., Gestion Resources Limited and Alan Minty, whereby CIVC under a complicated series of terms and conditions, as well as cash and stock transfers would be able to re-acquire 100% interest in the onshore Garden Hill Production Lease and offshore Exploration Licenses.

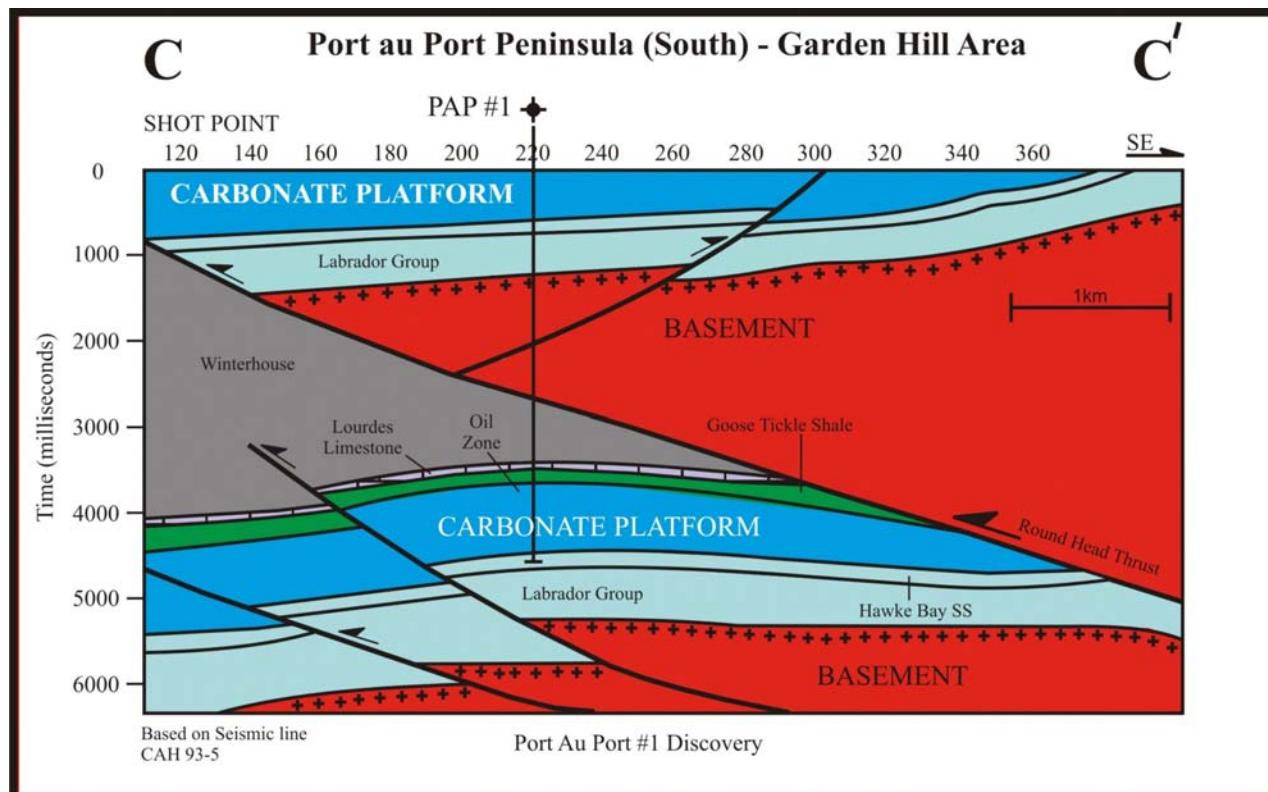
Under terms of the original Lease, CIVC had until August 2006 to achieve production at their Garden Hill site. Realizing this was not possible in such a short time frame, CIVC requested and received from Government, subject to various terms and conditions, a one year Lease extension. This extension was granted in June 2006 and allows the company and their partners time to achieve first production and formulate future exploration plans. On behalf of the interest holders, PDI Production Inc. (PDIP) assumed control of the project and re-entered the Port au Port #1 Sidetrack #2 well in late 2006 / early 2007 in order to conduct an extended well test. After producing excellent initial results, the test was terminated due to problems thought to be related to borehole constrictions within open-hole shaly intervals. A further lease extension was granted in August, 2007 which specified that a drilling program must commence no later than August, 2008 with a minimum expenditure of \$10 million. In October, 2007 PDIP announced that it has signed an agreement with Nabors Drilling for the supply of Nabors Rig 57ETD for mobilization to the Port au Port Peninsula to commence the drilling program.

Elsewhere on the Port au Port Peninsula, Hunt / PanCanadian spudded the onshore to offshore Long Point M-16 well at the tip of Long Point in September 1995 and followed this in May 1996 by commencing the offshore St. George's Bay A-36 well approximately six kilometers south

west of the Port au Port Peninsula. Although both wells were deemed non-commercial, the off-shore A-36 well did contain zones of good to excellent vuggy and cavernous porosity plus bitumen and minor live oil shows within known reservoir horizons.

Within the same timeframe, in February 1996 Talisman et al. spudded the onshore to offshore Long Range A-09 well approximately 3 km south of the PAP #1 well. Unfortunately, the anticipated Aguathuna Fm. reservoir zone penetrated in PAP #1 was water bearing in this well. No further drilling activity took place until late 1998, when Inglewood Resources commenced the onshore to offshore Man O'War I-42 well near Campbell's Creek on the southern Port au Port Peninsula. This well experienced numerous drill related problems and had to be terminated before reaching its planned target depth. The I-42 well was quickly followed in February 1999 by the onshore to offshore Shoal Point K-39 well, drilled by PanCanadian Petroleum and partners Hunt Oil, Mobil and Encal. It was directionally drilled to a depth of 3035 metres to test a large structure located beneath Port au Port Bay. On May 26th, 1999, PanCanadian announced that the well had tested water and would be abandoned. In the fall of 2000 Memorial University's Earth Science Department acquired additional seismic data in the Shoal Point area that suggests the well may have missed the target. The area has since been licensed by Canadian Imperial Venture Corp.

Figure 14 - Port au Port Geological Cross Section



Within the Anticosti Basin of western Newfoundland, other areas besides the Port au Port Peninsula were targeted by petroleum companies during this latest round of exploration activity. In May 1997, Delpet Vinland spudded the Big Springs #1 well near Croque on the Northern Peninsula. Only minor gas shows were encountered and this well was subsequently plugged and abandoned. Further to the south, CIVC spudded the Indian Head #1 exploration well in the Stephenville area during December 2001. No hydrocarbons were encountered and the well was at first suspended and then abandoned at a depth of 804.6 metres.

Finally, in January 2004 Contact Exploration of Calgary commenced the Parsons Pond #1 well to test a large thrust bounded feature identified on seismic data previously acquired by Labrador Mining and Exploration in the mid-90s. This was the first well drilled in this area since 1965. Several companies, including Deer Lake Oil and Gas and Vulcan Minerals, partnered with Contact in this well. On April 12th, 2004, the well was cased and suspended after encountering minor shows in fracture zones. No plans have been announced to deepen the well, but seismic data indicates the presence of deeper targets at this location.

Bay St. George Sub-basin

Hydrocarbons were first noted in the Bay St. George basin by government geologists during the mid 1950 's while in the process of conducting shallow delineation drilling for the Flat Bay gypsum deposit. One hole encountered natural gas at a depth of 31.4 m within anhydrites of the lower Codroy Group, while a second intersected a petroleum bearing conglomerate at 107.3 m within the underlying Anguille Group. This hole was terminated at 120.4 m after penetrating 13.1 m of oil stained rock. The first petroleum test hole, Anguille H-98 was drilled by Union Brinex in 1973 within the southern portion of the basin. This well went to a depth of 2311 m and encountered only trace percentages of poorly developed porosity.

The current round of activity commenced in June 1996, when Sandhurst Roxana of Tulsa, Oklahoma, shot 72 km of seismic data along roads in the Flat Bay area. In November 1996, London Resources Inc. drilled a stratigraphic (test) core hole adjacent to the oil-bearing, gypsum mining hole drilled during the mid 1950s. The test hole encountered oil-bearing conglomerate at 138 metres and was still within the oil-bearing section when it was suspended at 154 metres "for possible future re-entry and analysis". In 1998, Newfoundland based Vulcan Minerals recorded a 6 km seismic line in the Flat Bay area, in preparation for drilling in 1999.

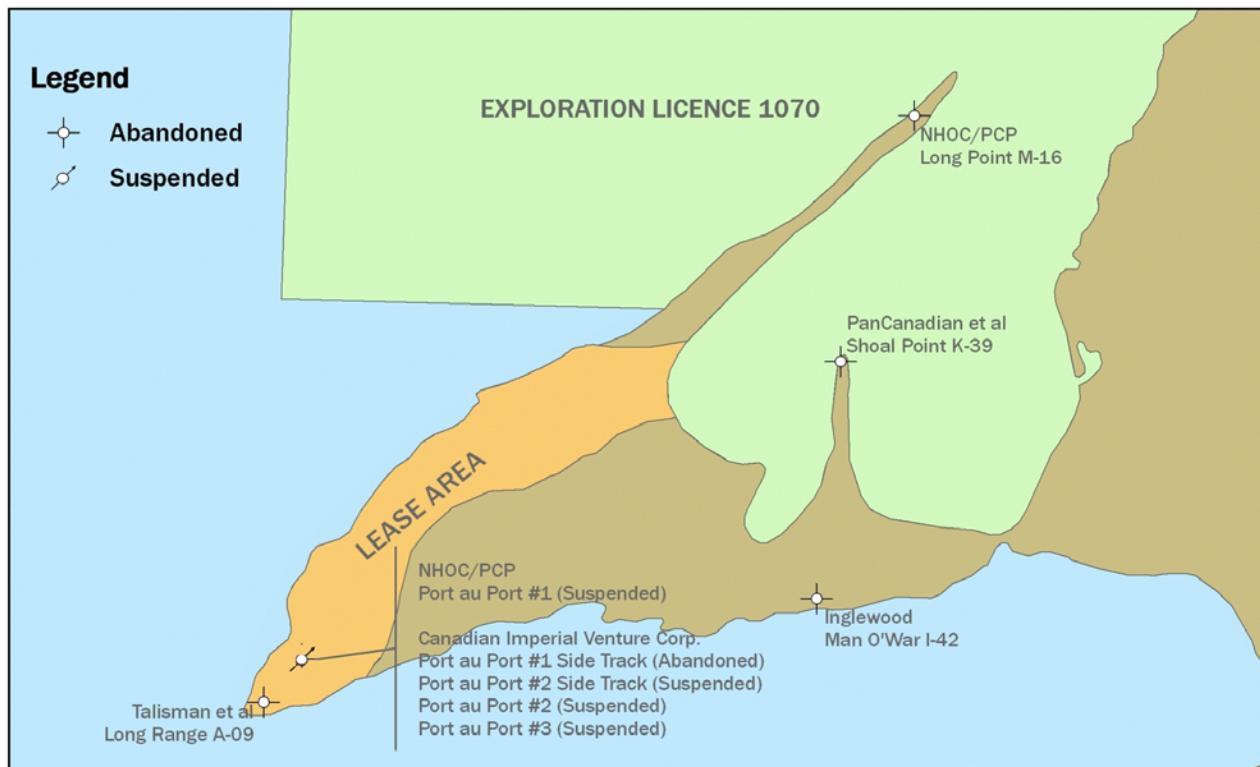
On August 10th, 1999, Vulcan Minerals spudded a 300 m well at Flat Bay to test a Carboniferous conglomerate target that was proven to contain live oil by the 1996 London Resources test hole. The well was drilled by a cable tool rig and on September 16th, 1999, Vulcan announced that the

well had encountered " significant oil shows over a gross interval exceeding 100 metres ". The company also indicated the geophysical logs indicate zones that may be commercially productive upon stimulation of the reservoir. The well was suspended at a depth of 286 metres.

Following upon the success of Vulcan Minerals, American Reserve Energy Corporation (AREC) of Tulsa, Oklahoma, drilled a well approximately three km to the east of the Vulcan Flat Bay site during 2000-01. This well encountered oil within fractured anhydrite, but had to be terminated, prior to entering a potential reservoir zone, due to drilling problems. In 2004, Vulcan Minerals drilled their Flat Bay #2 well immediately adjacent to the AREC well.

Vulcan Minerals Inc. spudded the Captain Cook #1 well in the Flat Bay area on December 19th, 2001. On January 30th, 2002, Vulcan announced the well had reached total depth and no commercial hydrocarbons had been encountered. Vulcan also acquired 19 km of seismic data in the Flat Bay area during January 2002. Vulcan drilled the 835m Flat Bay #2 well during 2004 and as reported encountered a low permeability oil zone (in excess of 100 metres) in the same formation as the Flat Bay #1 oil show. Vulcan completed a 60 km seismic program in December 2004. Vulcan re-entered the cable-tool Flat Bay #1 well in early March 2004, conducted a completion program and hydraulically fractured a 5-metre interval. The operator is still assessing the results, as well as proceeding with exploration.

Figure 15 - Well Locations Port au Port



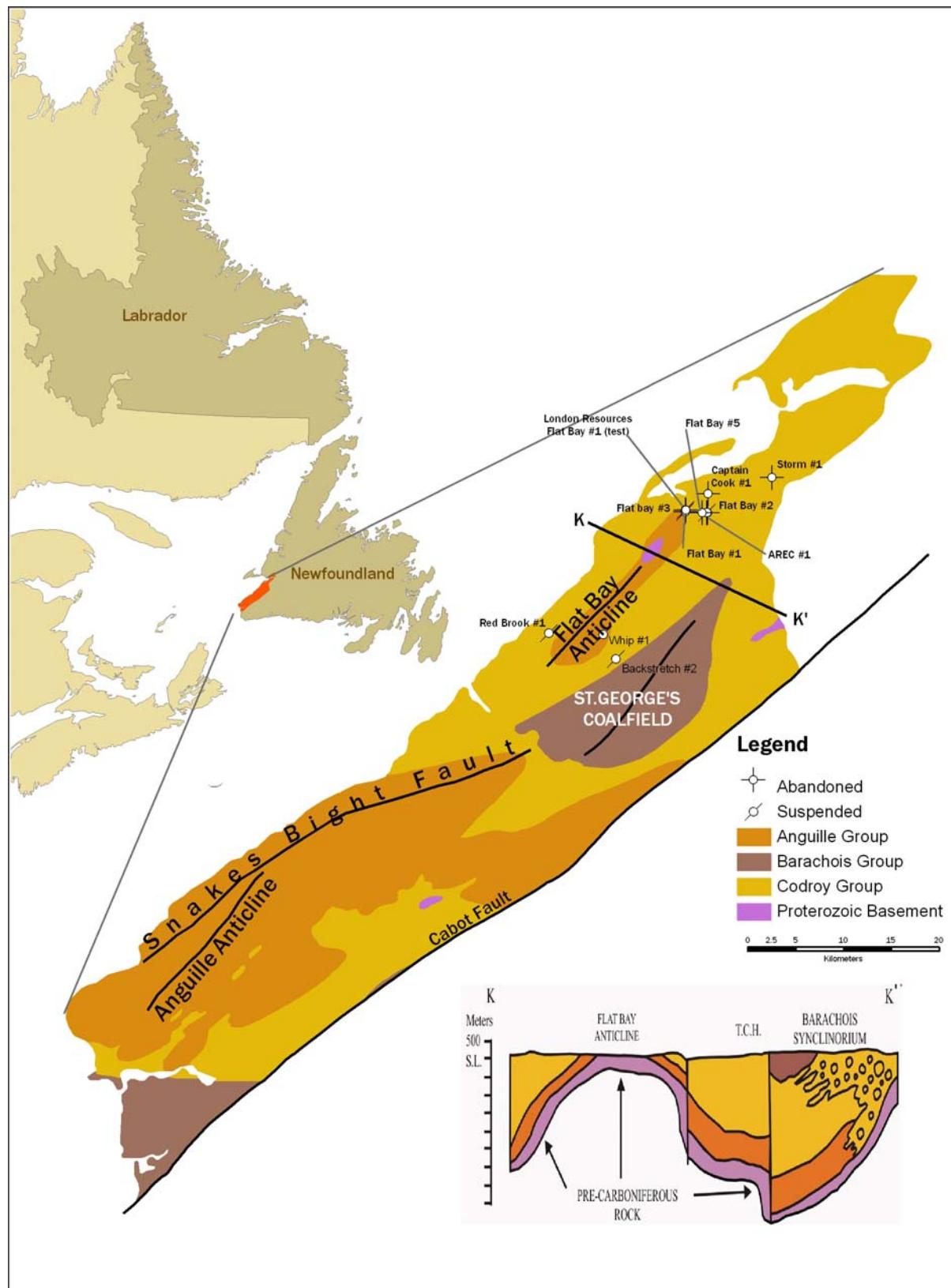
In 2005, Vulcan Minerals Inc. continued to be very active. The company had by early summer completed the purchase of a petroleum drill rig (Ingersoll Rand RD 10 top drive unit) and proceeded to put down four holes in the Bay St. George area before the end of the year. Three of these four holes (Storm #1, Backstretch #2 and Whip #1) were located over new prospect areas identified from previous seismic surveys, while the fourth (Flat Bay #3) was put down in close proximity to the original Flat Bay #1 petroleum discovery hole. All wells, except Storm #1 had oil and/or gas shows, primarily in the form of cuttings fluorescence or anomalous gas detector readings. The hydrocarbon shows as seen in the Whip #1 and Backstretch #2 wells, although minor are significant because they indicate an active petroleum system approximately 15 to 20 km to the south of the original Flat Bay #1 discovery. To further evaluate their land holdings, Vulcan also conducted a 70 line kilometer Vibroseis ground seismic survey and completed an Airborne aeromagnetics survey over their entire land holdings.

Based on their previous drilling results and seismic data in combination with the 2005 aeromagnetic survey, Vulcan re-assessed their exploration strategy for 2006 and targeted two structures for their exploration program. In late October, Flat Bay #5 was drilled as a further test of the oil bearing Flat Bay structure, however upon completion, the Company announced that the well would be plugged and abandoned. The second well named Red Brook #1 targeted an area approximately 20 km to the southwest of the original Flat Bay structure. This well encountered drill related problems and according to Vulcan, "the well has been suspended at a depth less than the targeted horizon ". Therefore, the Red Brook target is still untested, with re-entry and completion to be determined at a later date. Vulcan did not undertake a drilling program in 2007, although efforts continued to locate and mobilize a drill rig capable of reaching some of their deeper prospects. To further delineate prospects and leads in the northern Bay St. George area, approximately 57 km of off road 2D seismic data was acquired during the later half of 2007.

Deer lake Basin

According to historic records, petroleum exploration commenced in the Deer Lake Basin just prior to World War I , whereby a local syndicate put down two wells to evaluate the oil shale potential along the western side of the basin. Results from this activity are unknown and records indicate no further drilling until T. Landell-Mills acting on behalf of the Colonial Oil Shale and Chemical Company drilled three shallow wells in the same area between 1919 to 1921. Very little remains today of the original well logs, but a partial section of log from Mills #1 indicates that "small amounts of gas were blown out intermittently while drilling; however, strongest gas pressures were encountered further downhole over several intervals between 120 to 250 m. The intensity of these gas eruptions caused the drilling assembly to be completely blown out of the well. " Beyond this, petroleum interest remained dormant until 1954 when Claybar Uranium and Oil Ltd.

Figure 17 - Bay St. George Well Locations and Geological Cross Section



and Newkirk Mining conducted an exploration/mapping program and followed this up with a four well program during 1955 and 1956. Excellent oil and gas shows were recorded in two of these wells.

No further activity took place until 2000-2001, when Deer Lake Oil and Gas Ltd. (DLOG) drilled the 1879 m Western Adventure #1 well in the Deer Lake Basin. This well had a condensate show at 850 m and flowed gas on drillstem test at a rate of 100,000 cubic feet per day at 1600 m. DLOG has indicated that it plans to do further testing on this well. In the fall of 2002, DLOG drilled the Western Adventure #2 well in the Deer Lake Basin. This well is reported to have "encountered gas shows in porous and fractured zones at several levels". Based on drillstem results from Western Adventure #1, DLOG submitted a Development Plan Application to Government on March 11, 2003. In June 2005 the Company re-entered the Western Adventure #1 well and two upper zones were perforated and tested but there was no hydrocarbons flow to surface. The well is currently suspended as the Company evaluates the results of the testing program.

On September 19th, 2006 DLOG submitted an updated Development Plan Application for the western Adventure Field. The updated Application outlines the additional work which has to be done by the Company in order to eliminate work deficiencies noted by Government in the original 2003 Development Plan Application. Beyond this, DLOG continued to evaluate their land holdings during 2007 and are anticipating an ambitious exploration program in 2008.

Figure 16 - Deer Lake Basin Geological Cross Section

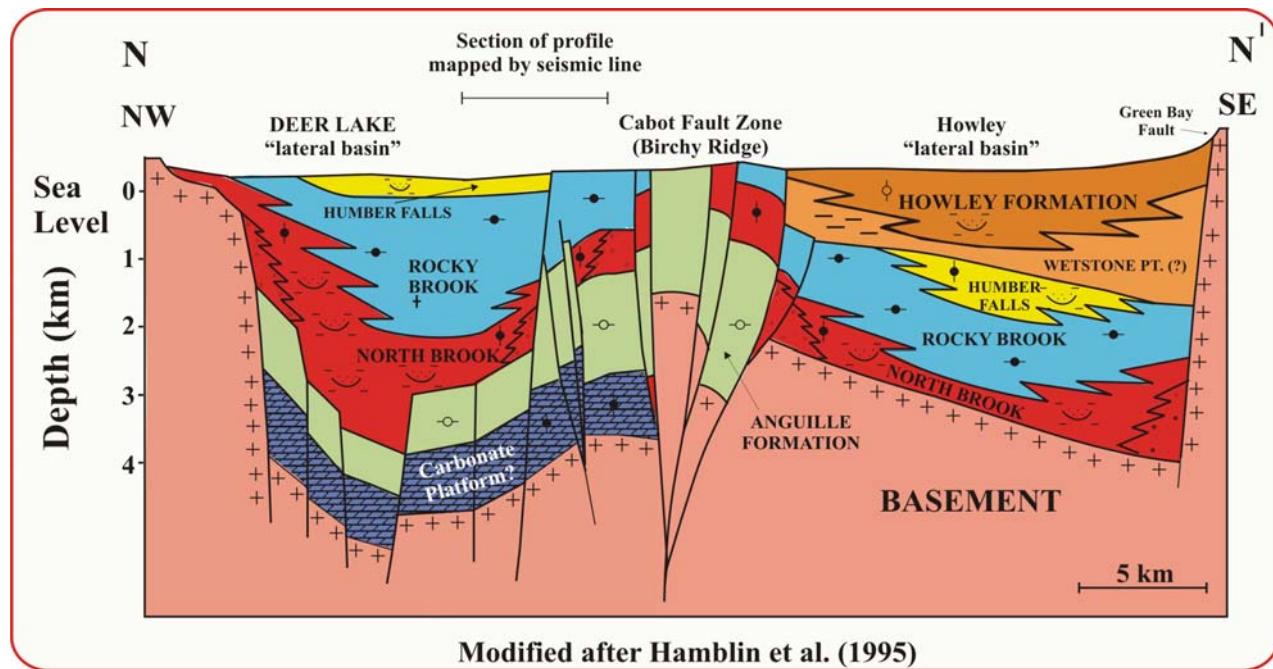
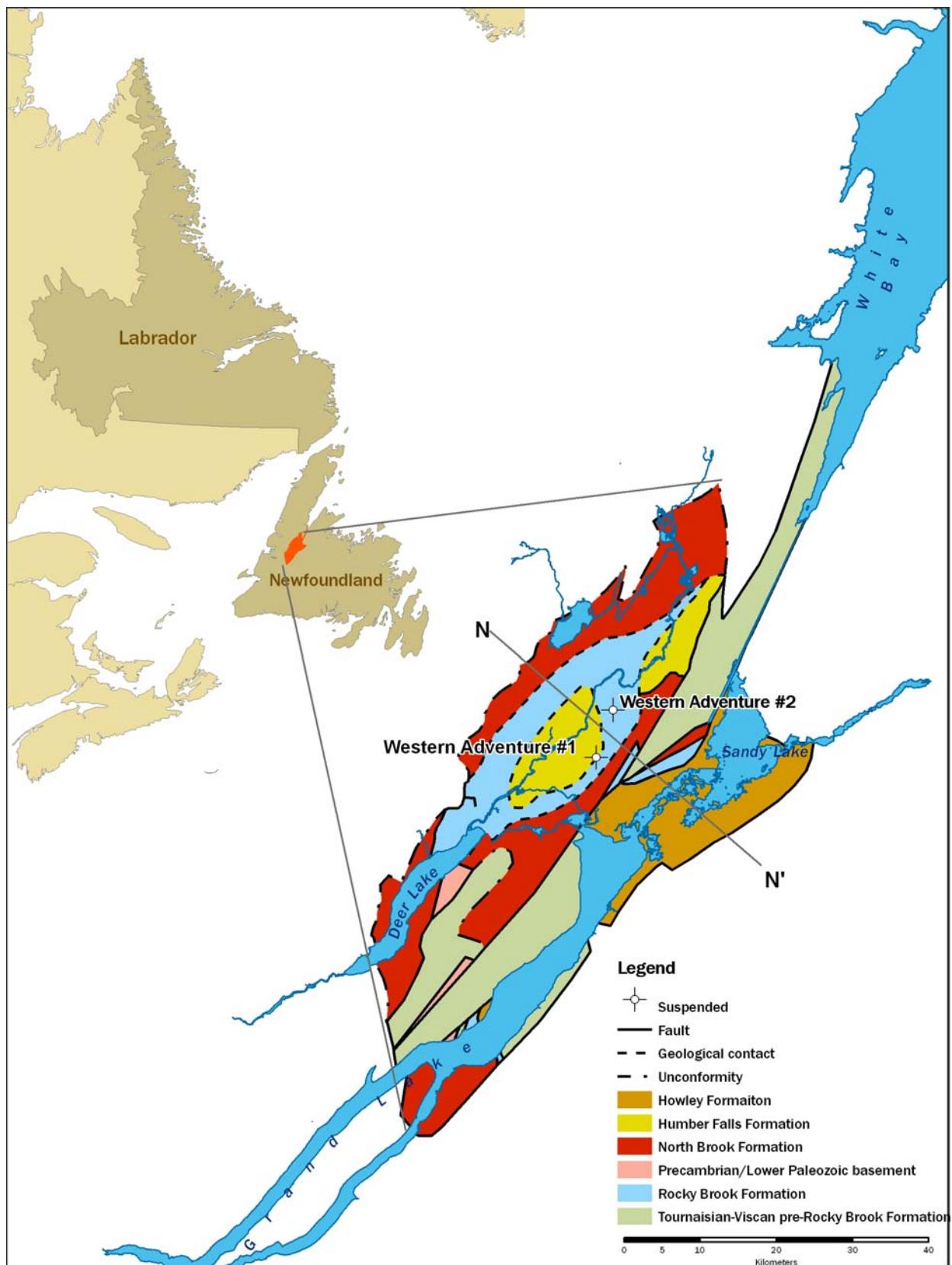


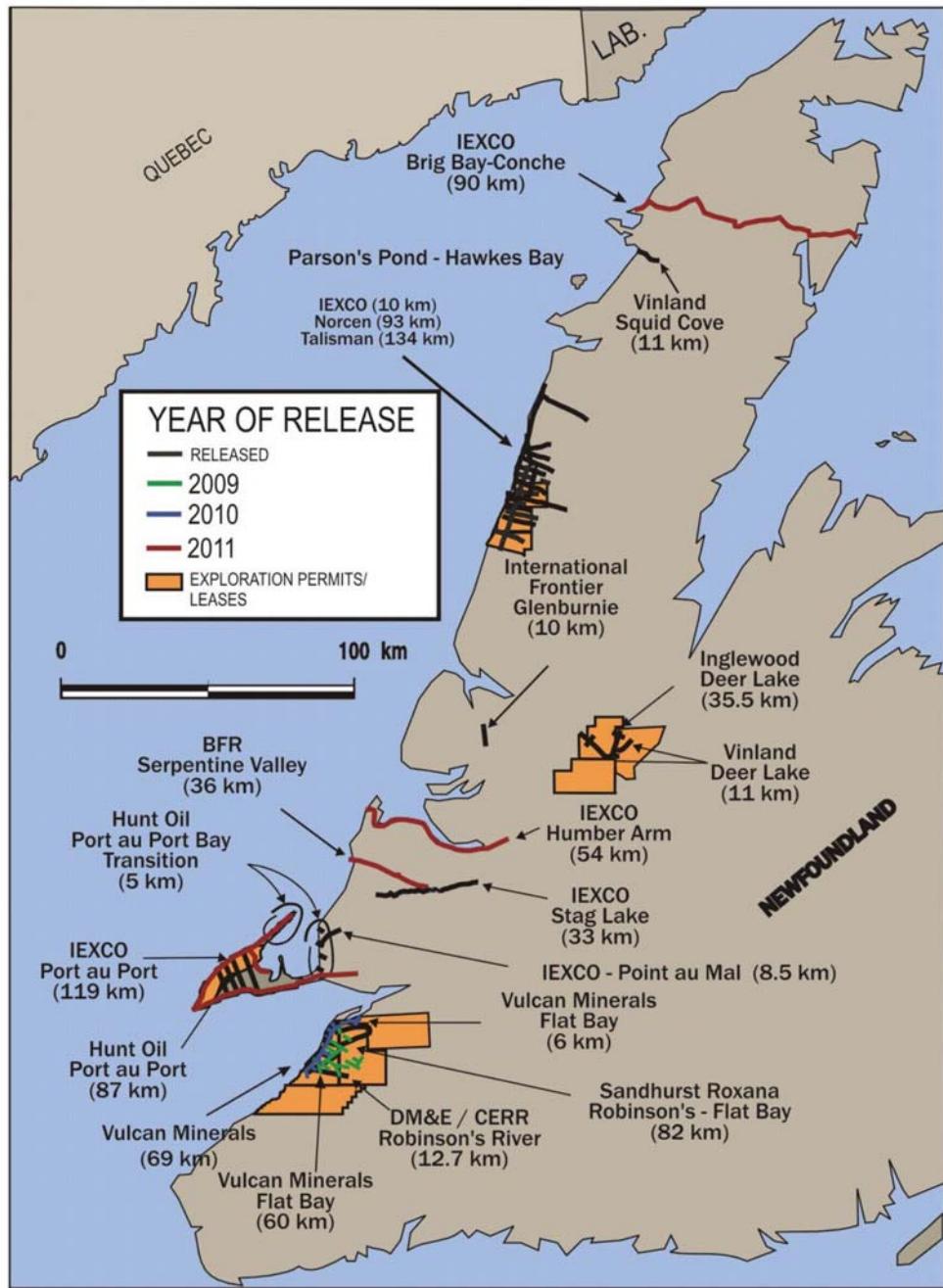
Figure 18 - Well Locations Deer Lake Basin



Onshore Seismic Activity

To date, there is a total of 1055 km of 2D seismic data in the onshore region of Newfoundland (Figure 19). In 2007, Vulcan Minerals completed a 57 km 2D seismic survey in the Bay St. George sub-basin. PDIP completed line cutting for their 115 km 2D program in the Garden Hill North area with plans to complete the survey in 2008.

Figure 19 - Onshore Western Newfoundland Reflection Seismic Lines



Energy Corporation

Background

In May 2007, Government, through the *Energy Corporation Act*, created an Energy Corporation that will act as a holding company to separate the regulated operations of Newfoundland and Labrador Hydro from the unregulated activities, including oil and gas development, associated with the Energy Corporation's expanded mandate. The new Energy Corporation is wholly owned by the Province, which in turn owns 100 percent of Hydro and its subsidiaries.

The Energy Corporation will take a lead role in the Province's participation in the development of our energy resources through such things as equity participation in oil and gas projects.

All activities engaged in by the Energy Corporation will be consistent with, and guided by, the Province's approach to energy development outlined in the Provincial Energy Plan released in September 2007.

Petroleum Exploration Enhancement Program (PEEP)

In the spring of 2007, the Province announced its investment, through the new Provincial Energy Corporation, in a Petroleum Exploration Enhancement Program (PEEP) to boost new petroleum exploration in Western Newfoundland. PEEP will encourage onshore exploration by providing funding to the new Energy Corporation to strategically invest in geoscientific activities. The Corporation will have the flexibility to commission seismic work independently and/or partner with private companies.

The program offers \$5 million over two years to assist companies in obtaining crucial geoscientific information in exchange for an equity position in future onshore projects.

Offshore Seismic Funding Assistance

In the Energy Plan, the Province has also committed to invest \$20 million over the next three years, through the Energy Corporation, to purchase existing proprietary seismic data for re-evaluation and acquire new data for the offshore sector.

Offshore Natural Gas Royalty Regime

The framework for the Province's new Offshore Natural Gas Royalty Regime was released on September 11, 2007 in the Province's Energy Plan, *Focusing Our Energy*. In designing the Offshore Natural Gas Royalty Regime, the province had five principle objectives:

- 1/ Encouraging development of economic projects;
- 2/ Obtaining higher royalties from a project when prices and profitability are higher and providing "downside protection" for developers in low price environments;
- 3/ Creating a predictable and transparent system;
- 4/ Designing a system that is sufficiently flexible to adapt to different types of projects; and
- 5/ Ensuring the regime is internationally competitive.

The royalty is comprised of two components: basic royalty and net royalty. Basic royalty is a deduction from net royalty. Both the Basic Royalty rate and the Net Royalty rate are determined by a smooth formula rather than the previous "step-based" royalty rates.

Basic Royalty provides a revenue stream to the province at all stages of a project's productive life. The royalty rate is driven by realized prices (net of transportation costs).

Netback Price (NP)	Basic Royalty Rate (BRR)
< Cdn\$4 (NP _{min})	2% (BRR _{min})
> Cdn\$8 (NP _{max})	10% (BRR _{max})

where Netback Price is the calculated price to the project net of transportation costs.

$$BRR = BRR_{min} + \{ [(NP - NP_{min}) / (NP_{max} - NP_{min})] * (BRR_{max} - BRR_{min}) \}$$
$$\text{Basic Royalty} = (\text{revenue} \underline{\text{less}} \text{ transportation costs}) * BRR$$

Fiscal Systems

Net Royalty is a profit-driven royalty that applies once the project has recovered its costs. The royalty is calculated on a project's net revenue (Revenue less transportation costs, project capital & operating costs, and basic royalty paid). As projects recover multiples of their project costs, the net royalty rate climbs. This royalty is calculated as follows:

R Factor (R)	Net Royalty Rate (NRR)
< 1 (R_{min})	0% (NRR_{min})
> 4 (R_{max})	50% (NRR_{max})

where $R = (\text{cumulative revenue less cumulative transportation costs less cumulative royalty paid}) \text{ divided by } (\text{cumulative project capital \& operating costs})$

$$NRR = NRR_{min} + \{ [(R - R_{min}) / (R_{max} - R_{min})] * (NRR_{max} - NRR_{min}) \}$$
$$\text{Net Royalty} = (\text{revenue less transportation costs less project capital \& operating costs less basic royalty paid}) * NRR$$

The Offshore Natural Gas Royalty Regime has not yet been enacted in legislation. The Province continues to review implementation issues for the regime in consultation with industry stakeholders. The province also reserves the right to consider modifications of this regime to recognize the infrastructure costs associated with the "pioneer project" that leads to development of new infrastructure.

Offshore Oil Royalty Regime

A new Generic Offshore Oil Royalty Regime is under development and will be guided by the principles of the Energy Plan. It is expected that the new Generic Offshore Oil Royalty Regime will be similar in structure to the Offshore Natural Gas Royalty Regime.

Onshore Oil Royalty Regime

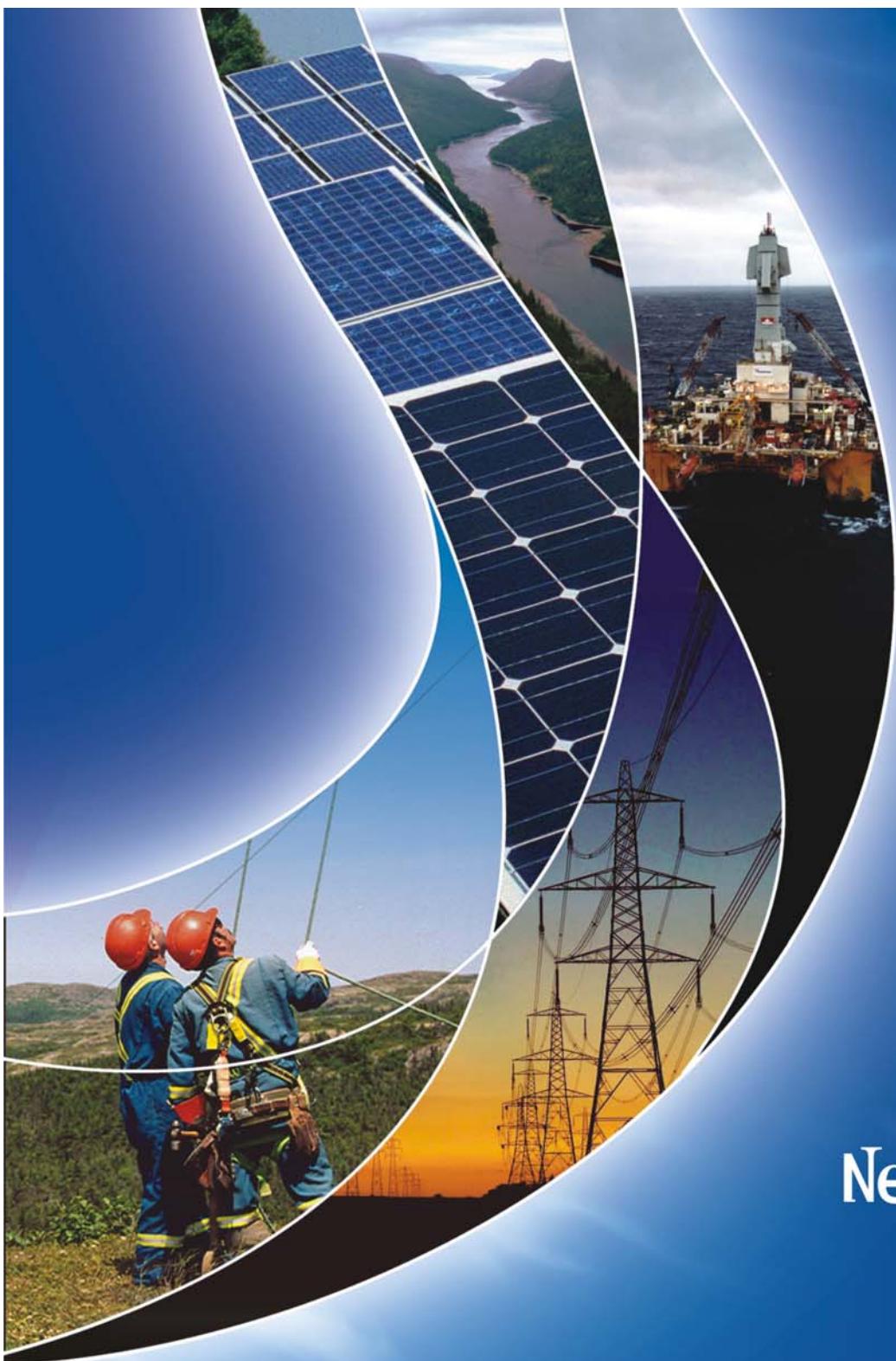
Royalty Holiday	
First 2 million barrels	
Basic Royalty	
5%	
Net Royalty	
Tier 1	20%
	Rate
	Return Allowance
Tier 2	5% plus LTGBR*
	Rate
	Return Allowance

There is no royalty payable on the first two million barrels or equivalent of production for a project. After two million barrels of production, a Basic Royalty of five percent is payable.

Net Royalty commences to be payable upon the occurrence of Net Royalty Payout. When costs are recovered and the Tier 1 Return Allowance is achieved, the Tier 1 Net Royalty rate becomes applicable. The Basic Royalty paid is applied as a credit against any Tier 1 Net Royalty payable and, as a result, royalties payable for any particular period would be the greater of the Basic Royalty or the Tier 1 Net Royalty.

When the Tier 2 Return Allowance is achieved, the Tier 2 Net Royalty rate becomes applicable. The Tier 2 Net Royalty is in addition to any other royalties payable.

* Long Term Government Bond Rate



Newfoundland Labrador

Department of Natural Resources
P. O. Box 8700
St. John's, NL
Canada, A1B 4J6

t: 709-729-0579
f: 709-729-4011
e: petroleum@gov.nl.ca
w: www.nr.gov.nl.ca/nr