Petroleum Resource Development

Activity Report - 2011

Newfoundland Labrador

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Department of Natural Resources
Petroleum Development
Activity Report - 2011

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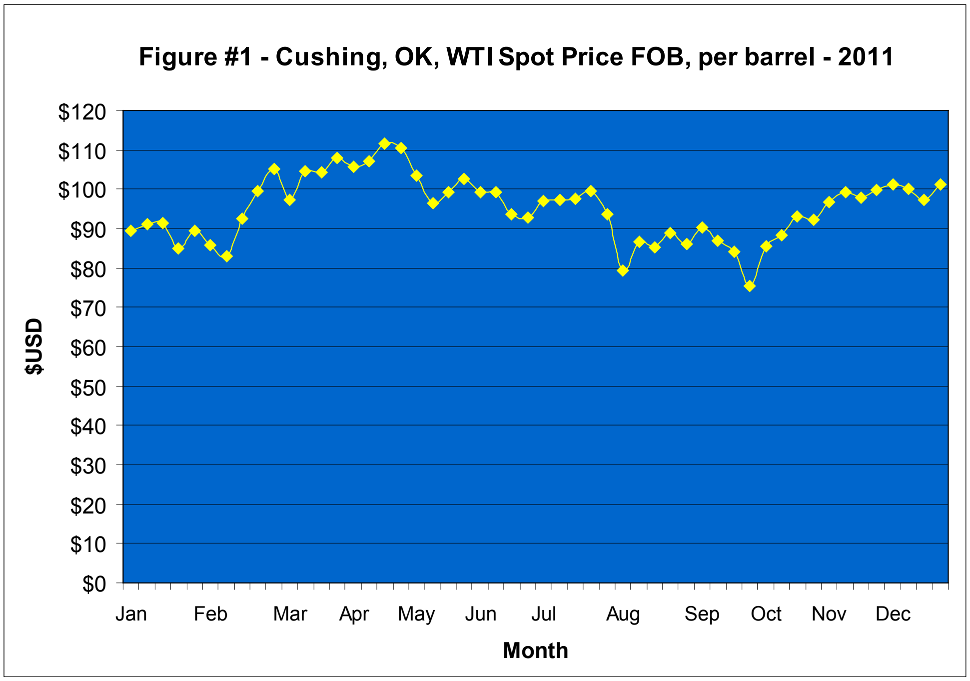
1.0 Introduction

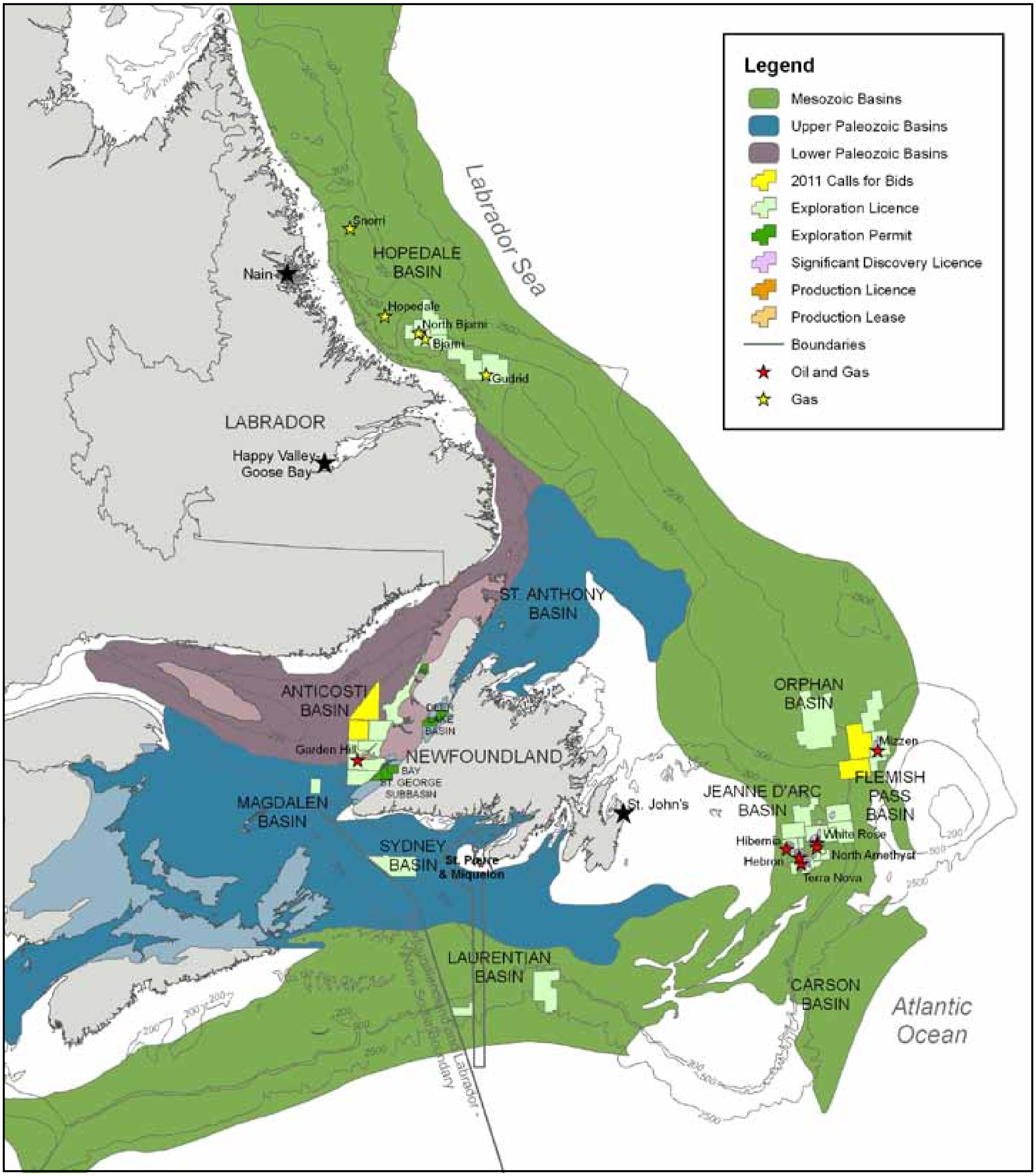
Located on Canada's east coast, the Province of Newfoundland and Labrador has established itself as Canada's offshore oil producing region. Over the past 14 years the province's four producing fields; Hibernia, Terra Nova, White Rose and North Amethyst have produced approximately 1.3 billion barrels of oil. In 2011 total production was 97.3 million barrels of oil which represented approximately 10% of Canada's crude output and 30% of its light crude production.

As shown by the graph below, the price per barrel (USD) of West Texas Intermediate (WTI) crude oil fluctuated from the high $70s to over $114 giving an average price per barrel of approximately $98 during 2011. The value of Newfoundland and Labrador's output was approximately $10 billion in 2011 which represented approximately 35% of the province's gross domestic product (GDP).



As of December 31, 2011 there has been a total of 371 wells spud offshore Newfoundland and Labrador commencing with the Tors Cove D-52 exploration well. The well was spud on June 7, 1966 by partners Pan American Petroleum and Imperial Oil. The 371 wells are comprised of 171 development, 52 delineation and 148 exploration. With respect to the onshore portion of the province, approximately 90 wells have been spudded. The first well dates back to 1867 and was drilled in the Parson's Pond area of the Northern Peninsula. Exploration and development continued both offshore and onshore in 2011 and this report

Figure #2 - Sedimentary Basins of Newfoundland and Labrador



highlights the petroleum development activity within the province's many sedimentary basins.

Currently Newfoundland and Labrador has less than 10% of prospective onshore and offshore land held under license by various operators. The total potential acreage, as outlined on the Sedimentary Basins Map on page 2, is in excess of 80 million hectares offshore and 1.5 million hectares onshore. As the map illustrates, the numerous offshore sedimentary basins are located throughout Newfoundland and Labrador whereas the onshore potential is focused around the western portion of the island of Newfoundland only.

Petroleum activity in Newfoundland and Labrador is regulated by two distinct authorities. For offshore activity, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is responsible, on behalf of the Federal Government of Canada and the Provincial Government of Newfoundland and Labrador, for petroleum resource management. With respect to the onshore, the Provincial Government of Newfoundland and Labrador has sole management authority.

The C-NLOPB issues land rights in three different classes; exploration licenses, significant discovery licenses and production licenses. As of December 31, 2011 the C-NLOPB had 32 exploration licenses, 51 significant discovery licenses and 10 production licenses on record. During 2011 successful work expenditure bids totaling $349,776,664 CAD were received on Calls for Bids conducted in the Anticosti and Flemish Pass basins. Exploration licenses will be issued on these land parcels early in 2012 when all relevant terms and conditions are met.

With respect to the onshore area, the Government of Newfoundland and Labrador issues land rights in two categories; exploration permits and production leases. As of December 31, 2011 the province had seven exploration permits and one production lease on record. The exploration licenses onshore, encompassing approximately 187,303 hectares, have been issued in three general areas in western Newfoundland; Flat Bay, Deer Lake and Parsons Pond. The production lease is issued to PDI Production Inc. at the Garden Hill site located on the Port au Port Peninsula. The regional activity section in Section 3.0 of this report details the relevant activity at each location.

A total of 51 significant discovery licenses have been issued by the C-NLOPB in 25 areas including five on the Labrador Shelf, 19 in the Jeanne d'Arc Basin and one in the Flemish Pass Basin. While the C-NLOPB has issued a significant discovery license to Statoil for their Mizzen discovery in the Flemish Pass Basin, they have not released a resource estimate on

Table #1

Petroleum Reserves[1] and Resources[2] Newfoundland Offshore Area

Field	Oil		Gas		NGLs[3]	
	10^6 m^3	million bbls	10^9 m^3	billion cu. ft.	10^6 m^3	million bbls
Grand Banks						
Reserves						
Hibernia	221.9	1395				
Terra Nova	66.6	419				
Whiterose [4]	36.3	229				
North Amethyst	10.8	68				
Sub-Total	335.6	2110				
Produced[5]	204.8	1288				
Remaining Reserves	130.8	822				
Resources						
Hibernia			55.9	1984	35.8	225
Terra Nova			1.5	53	0.6	4
Whiterose [6]	12.1	76	85.3	3023	15.3	96
North Amethyst			8.9	315		
Hebron	92.4	581	-	-	-	-
Ben Nevis	18.1	114	12.1	429	4.7	30
West Bonne Bay	5.7	36	-	-	-	-
West Ben Nevis	5.7	36	-	-	-	-
Mara	3.6	23	-	-	-	-
North Ben Nevis	2.9	18	3.3	116	0.7	4
Springdale	2.2	14	6.7	238	-	-
Nautilus	2.1	13	-	-	-	-
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
Sub-Total	150.3	946	191.9	6804	60.3	379
Labrador Shelf						
North Bjarni	-	-	63.3	2247	13.1	82
Gudrid	-	-	26	924	1	6
Bjarni	-	-	24.3	863	5	31
Hopedale	-	-	3	105	0.4	2
Snorri	-	-	3	105	0.4	2
Sub-Total	0	0	119.6	4244	19.9	123
Total Resources	150.3	946	311.5	11048	80.2	502

1 "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. Oil reported for Hibernia, Terra Nova, White Rose (South Avalon and Southern Extension) and North Amethyst Fields are classified as reserves.

2 "Resources" are volumes of hydrocarbons, expressed at 50% probability, assessed to be technically recoverable that have not been delineated and have unknown economic viability. The classification of recources includes gas, NGLs, and oil in pools and fields that have not yet been developed or approved by the C-NLOPB.

3 "Natural Gas Liquids" (NGLs) are derived from natural gas, which is the portion of petroleum that exists in either the gaseous phase or in solution in crude oil in natural underground reservoirs.

4 White Rose Reserves contain South Avalon Pool and Southern Extension Pool.

5 Produced reserve oil volumes as of December 31, 2011. These also include a small quantity of natural gas liquids.

6 White Rose Resources contain West Avalon Pool, North Avalon Pool and Hibernia Reservoir.

* NGL estimates have not been updated since 2006.

the size of the discovery. A resource estimate is not expected to be released until the results of the appraisal have been completed.

Exploration continued in Newfoundland and Labrador at a high level in 2011. Chevron and Statoil completed major 3D seismic programs in the Flemish Pass Basin and the TGS NOPEC Geophysical Company/Petroleum Geo-Services Inc led consortium, Multi Klient Invest, commenced their major 22,000 kilometer 2D seismic program offshore Newfoundland and Labrador. In 2011 the program focused its attention offshore Labrador. With respect to exploration drilling, Statoil completed a well at their Fiddlehead prospect in the Jeanne d'Arc Basin and also a delineation well at their Mizzen discovery in the Flemish Pass Basin. On the western portion of the province, Shoal Point Energy continued working on their 3K-39 well which is on onshore to offshore well targeting the Green Point Formation. Lastly Vulcan Minerals further advanced their understanding of the oil deposit at Flat Bay by drilling 6 test holes.

Work also continued in 2011 on the Hebron project, which is expected to be the province's fifth producing oil field. The Development Plan application was filed with the C-NLOPB in April, 2011 on the proposed development. The capital cost of the total program is estimated at $8.3 billion which includes the gravity based structure (GBS) and topsides facilities as well as $1.9 billion for drilling operations. Construction on the Hebron project is scheduled to commence in 2012 and first oil is expected in 2017.

First oil was achieved at several extension/tieback projects in 2011. The Hibernia South Extension (HSE) Unit produced first oil on June 25, 2011. This follows first oil from the Hibernia Southern Extension - AA Block which occurred on November 27, 2009. At the West White Rose pilot program first oil was achieved on September 25, 2011. Both of these projects require additional development work prior to full production being established.

Husky Energy announced during the year that they were investigating the feasibility of constructing a wellhead concrete gravity structure (CGS) for the White Rose field. Plans call for it to be located in the West White Rose area but would have the ability to drill wells in many parts of the White Rose field. Expressions of interest were issued for the front end engineering and design (FEED) with bids due early in 2012.

2011 closed with a slight slow down in drilling activity with two of the mobile offshore drilling units operating in Newfoundland waters, the GSF Grand Banks and the Henry Goodrich, coming out of service for extended periods. The GSF Grand Banks was damaged when a supply ship collided with it while drilling a well at the White Rose field. The GSF Grand

Banks was scheduled for its five year survey for recertification in early 2012 and it was therefore decided to bring the rig into Irving's Halifax Shipyard facility to complete the repairs and recertification at the same time. The expected downtime to complete the work is estimated at 60 days. The Henry Goodrich was also due for a major turnaround program and late in 2011 the rig was relocated to the Gulf of Mexico for repairs and upgrades. Once the work is completed, which is estimated to take 70 days, the rig will return to Newfoundland and Labrador waters to continue exploration and development work on behalf of the rig sharing partners; Statoil, Husky and Suncor.

Production in 2012 is expected to be substantially lower than that achieved in 2011 as both the Terra Nova FPSO and Sea Rose FPSO are planned to come out of service for maintenance programs. This will result in reduced production at the Terra Nova, White Rose and North Amethyst fields. However, petroleum exploration activity is expected to be maintained at a high level in 2012. Outstanding offshore work commitments total $1.3 billion CAD as of December 31, 2011 and plans are being finalized for extensive seismic programs on the North Grand Banks and also in Labrador in 2012. Western Geco plan for a major non-exclusive 3D survey on the North East Grand Banks which is the first non-exclusive survey to be completed in the area in many years. Multi Klient Invest will be continuing with their 22,000 kilometer 2D survey which they commenced in 2011.

With respect to new exploration wells in 2012, Chevron Canada have announced plans for another exploration well in the Orphan Basin and Statoil are considering a multi well exploration program in the Flemish Pass Basin. Further, Husky Energy has several drill ready prospects identified in its east coast portfolio which it will be pursuing in 2012. This exploration activity combined with development work continuing on the Hibernia, White Rose and Hebron projects demonstrates industry's continued confidence in the petroleum industry in Newfoundland and Labrador.

As of December 31, 2011 Newfoundland and Labrador had discovered reserves/resources of 3.1 billion barrels of oil and 11 trillion cubic feet of natural gas as detailed in Table #1 on page 4. Geoscience data indicates that a further 6 billion barrels of oil and 60 trillion cubic feet of natural gas remain undiscovered.

2.0 Field Development Summary

2.1 Hibernia - Main Field

Hibernia Project - Ownership (Main Field)	
ExxonMobil	33.125%
Chevron	26.875%
Suncor	20%
Canadian Hibernia Holding Corp.	8.50%
Murphy Oil	6.50%
Statoil ASA	5%

The Hibernia field, the first field development in the Newfoundland and Labrador offshore region, remains the province's largest offshore oil project in terms of recoverable reserves. The field was discovered in 1979 by Chevron et al with the drilling of the Hibernia P-15 well. The well was drilled approximately 315 kilometers east southeast of St. John's, NL in about 80 meters of water. A fixed production platform consisting of a gravity-based structure (GBS) and topsides drilling and production facilities are being utilized to produce the field. The platform is 224 meters tall, weighs 1.2 million tonnes and can store 1.3 million barrels of oil. Shipments of oil from Hibernia are offloaded at the purpose built transshipment facility at Whiffen Head, Placentia Bay, NL.

Production from the Hibernia field to date has been from two main reservoirs; Hibernia and Ben Nevis/Avalon. Hibernia field development was based on an original reserve estimate of 520 million barrels of oil at an average annual oil production rate (APR) of 110,000 barrels of oil per day (bopd). There have been several increases to the oil reserve estimate and in 2010 the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) increased the recoverable reserves estimated for the Hibernia field to 1.395 billion barrels of oil, 1.984 trillion cubic feet natural gas and 225 million barrels of natural gas liquids. The current approved annual production rate for the Hibernia platform is 220,000 barrels of oil per day.

Hibernia GBS

During 2011 several large upgrade and maintenance projects were completed at the Hibernia platform. Equipment was installed to assist with gas lift and the two offshore loading systems that transfer crude oil from the platform to oil tankers were replaced. The $200 million gas lift project was executed as an artificial lift method lightening the weight of liquids being produced, which should help to increase oil production. Technip Canada was the major contractor on the offshore loading system replacement, valued at $200 million, and they used two vessels, the Wellservicer and the Deep Constructor, to complete the program.

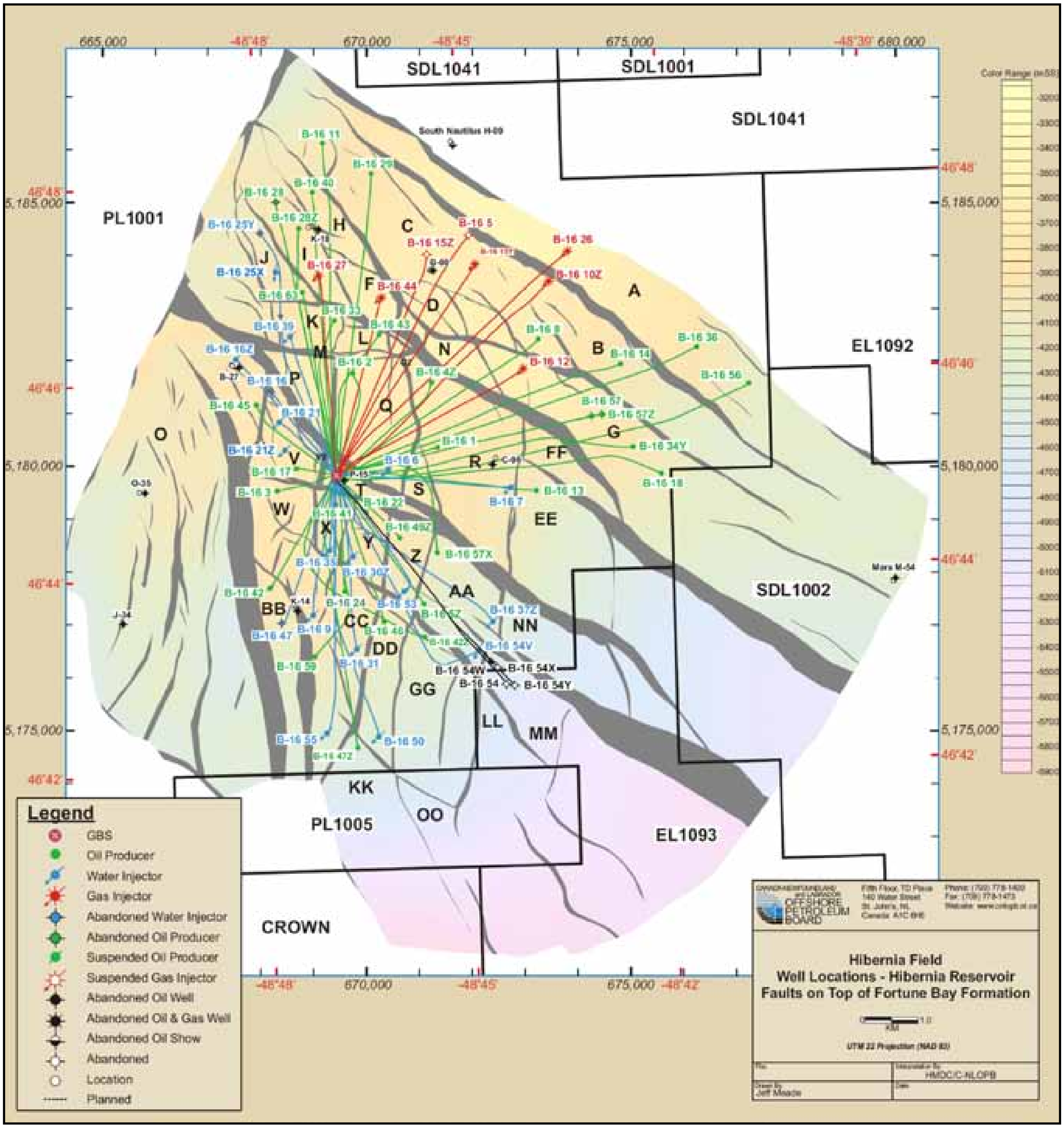
As of December 31, 2011 Hibernia was operating with 62 development wells as shown in Figure #3 on page 9. They include 34 oil producers, 22 water injectors and 6 gas injectors. Hibernia produced 56.3 million barrels of oil during 2011 giving an average daily production of 154,383 bopd. Cumulative oil production to December 31, 2011 was 779.3 million barrels representing 55.9% of the total current reserve estimate. Oil production in 2011 was similar to that achieved in 2010.

In June 2009 it was announced that the Hibernia project had reached payout; the time at which all development costs have been recovered. As a result of this milestone, the Province of Newfoundland and Labrador is now receiving a royalty rate of 30% for oil extracted from the main part of the Hibernia field.

Additional drilling around the original Hibernia discovery in 2005 and 2006 confirmed significant upside reserves in the southern portion of the Hibernia field. This area, described as the Hibernia Southern Extension, is divided into two parts; the Hibernia AA Block and the Hibernia South Extension (HSE) Unit. Figure 4 located on page 11 shows the two sections within the Hibernia Southern Extension.

A Memorandum of Understanding to develop the southern portion of the field was signed with the Province on June 16, 2009. Subsequent to this agreement, the C-NLOPB approved amendments to the Hibernia Development Plan on August 18, 2009 and September 2, 2010 to accommodate the development of the AA Block and the HSE Unit respectively. Details on each of these projects are outlined in sections 2.1.1 and 2.1.2 of this report. Oil production from both the AA Block and HSE Unit will partially offset the natural production decline at the main Hibernia field and extend the life of field development for the Hibernia platform. It is now expected that the Hibernia platform will continue to produce oil until 2040. Once natural gas is produced on a commercial basis this timeframe could be extended further.

Figure #3 - Hibernia Field Well Locations



2.1.1 Hibernia Southern Extension - AA Block

Figure 4 on page 11 shows the location of the Hibernia AA Block (includes AA1 and AA2) within the main Hibernia Production License PL-1001 and contained in the Hibernia reservoir. Work commenced on the block in late 2009 after the development plan amendment was approved by the C-NLOPB. The development program for the AA Block includes drilling four wells directly from the Hibernia platform. The four well drilling program, which was completed in 2010, consisted of two pairs of oil producers (B16-57X and B16-5Z) and water injectors (B16-37Z and B16-54V).

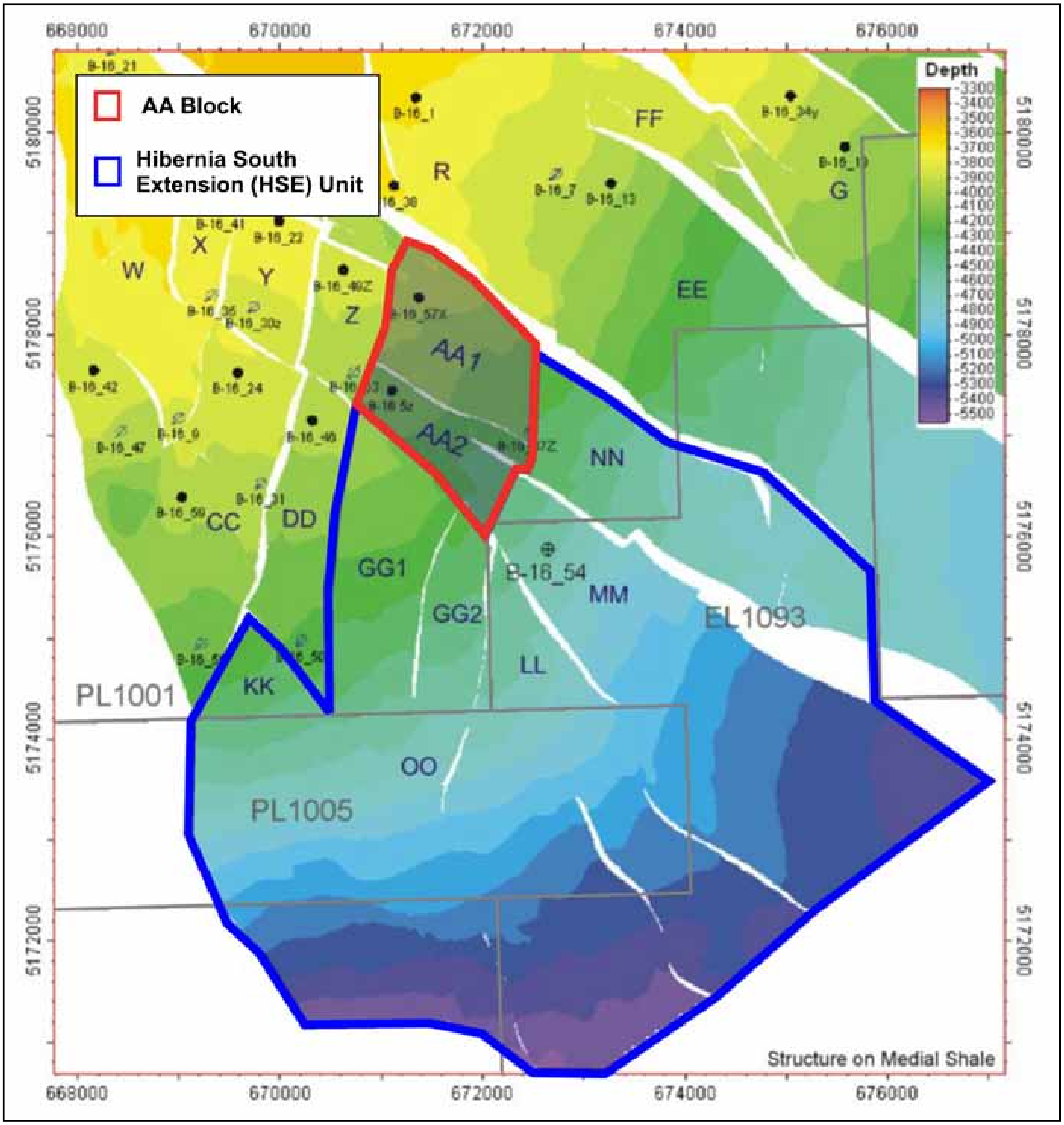
The C-NLOPB has assigned a recoverable reserve estimate of 48 million barrels of oil for the AA Block. Note that these reserves are included in the overall Hibernia recoverable reserve estimate of 1.395 billion barrels of oil mentioned previously in Section 2.1 - Hibernia - Main Field. Production from the AA Block was initially estimated to average 11,000 bopd with peak production reaching 25,000 bopd. The estimated costs for drilling and tie-in activities of the AA Block development was $196 million CAD and production was expected to last until 2024.

Production from the first oil producer (B-16-57X) occurred on November 27, 2009 and the second oil producer (B-16-5Z) was brought on line on July 28, 2010. In 2011 oil production from the two wells in the AA Block totalled 14.0 million barrels giving an average daily production of 38,398 barrels. The total cumulative production to December 31, 2011 was 22.3 million barrels of oil.

As part of the Hibernia Southern Extension Agreement signed with the province on February 16, 2010 an equity ownership of 10% was negotiated for Nalcor Energy - Oil and Gas, the province's wholly owned energy corporation. The purchase price of the ownership position was $30 million CAD and applies to any new development within the Hibernia Southern Extension, exclusive of the AA Block. In addition, Nalcor Energy agreed to cover 10% of future development costs in return for 10% of oil production. The ownership structure for the AA Block therefore remains the same as the original Hibernia Main Field as detailed on page 7.

However, the new agreement with the Provincial Government included an enhanced royalty rate of 42.5% from oil produced from the existing GBS within Hibernia Southern Extension. This new rate would therefore apply to production from the AA Block. The rate will increase to 50% once the terms of the supplementary royalty payout are achieved under the original Hibernia royalty contract.

Figure #4 - Hibernia Southern Extension



2.1.2 Hibernia Southern Extension - Hibernia South Extension (HSE) Unit

As part of the development plan amendment approved by the C-NLOPB on September 2, 2010 the interest holders in Production Licenses 1001 and 1005, and Exploration License 1093, were granted the right to develop the Hibernia reservoir located in the Hibernia South Extension (HSE) Unit as shown in Figure 4 on page 11. The additional area included in the amendment include the GG, KK, LL, MM, NN and possibly the OO fault blocks.

The C-NLOPB has estimated recoverable reserves in the HSE Unit at 167 million barrels of oil. Note that this figure is included in the 1.395 billion barrels of oil total reserve estimate for the Hibernia field. The total cost of the HSE development was estimated at $1.735 billion CAD with the drilling program expected to account for in excess of $1.1 billion CAD of the total.

The approved development plan for the HSE Unit includes the drilling of 10 wells comprising 5 pairs of production and water injectors. The production wells will be drilled from the Hibernia platform from existing GBS slots whereas the water injectors will be drilled when a semi-submersible offshore drilling unit is mobilized to the area. An excavated drill centre to accommodate the subsea templates and manifolds for the water injection wells will be located approximately 7 kilometers southeast of the Hibernia GBS. The flowlines and umbilicals will be connected to the Hibernia platform utilizing two existing J-tubes installed in the platform at the time of original construction.

Drilling of the oil production wells commenced in 2011 with first oil from wells B-16 47Z and B-16 42Z occurring on June 25, 2011 and September 30, 2011 respectively. As of December 31, 2011 the two wells produced a total 1.4 million barrels of oil. Major contracts were awarded in 2011 for parts of the subsea infrastructure associated with the HSE Unit. FMC Technologies signed a contract to supply up to six subsea injection trees and wellheads, one manifold and associated control systems. Technip Canada will build and install the 7 kilometer long flowlines and umbilicals connecting the water injectors to the platform. This equipment is scheduled for delivery in 2013 after the dredging of the excavated drill centre is completed.

As mentioned in Section 2.1, with the signing of the Hibernia South Development Agreement on February 16, 2010 with the Provincial Government, new fiscal measures were included encompassing production from the southern portion of the Hibernia Field. These new fiscal measures included a 10% ownership position for Nalcor Energy - Oil and Gas, exclusive of the AA Block development, and an enhanced royalty structure for all production covered within the Hibernia South Extension area.

The new royalty framework is divided between production from land licensed under the original Production License PL1001 and land licensed under both the Production License PL-1005 and Exploration License EL-1093.

With respect to new production from the HSE Unit from within the original PL-1001, the new royalty framework will consist of the current basic royalty rate of 30%. This rate will increase to 37.5% when the price of West Texas Intermediate (WTI) crude oil exceeds $50 USD per barrel and then increases to 42.5% when the price of WTI crude exceeds $70 USD per barrel. A top royalty rate of 50% will be applicable when the project meets the terms of the supplementary royalty payout under the terms of the original Hibernia royalty contract.

The new royalty structure for oil production from lands licensed under PL-1005 and EL-1093 calls for a basic 5% royalty rate from first oil. This rate increases to a Tier 1 rate of 30% when payout occurs on the project. The rate rises to 32.5% when WTI crude pricing exceeds $50 USD per barrel and then increases further to 37.5% when WTI pricing exceeds $70 USD per barrel. A top royalty rate of 50% will be applicable when the project meets the terms of the supplementary royalty payout under the terms of the original Hibernia royalty contract.

The new ownership structure in PL-1005 and El-1093 reflecting Nalcor's new position are shown in the following graphs.

PL 1005 Ownership	
Suncor	22.5%
ExxonMobil	22.5%
Statoil ASA	22.5%
Chevron	22.5%
Nalcor Energy	10%

EL 1093 Ownership	
ExxonMobil	29.8125%
Chevron	24.1875%
Suncor	18%
CHHC	7.65%
Murphy	5.85%
Statoil	4.5%
Nalcor Energy	10%

The Hibernia Southern Extension agreement also includes commitments that the proponents will comply with the C-NLOPB requirements on research, development, education and training. Further, the proponents agreed to spend $10 million within three years of first commercial oil production on one or more legacy projects and also includes a gender equity and diversity program for all phases of the project.

2.2 Terra Nova Field

Terra Nova Project - Ownership	
Suncor	37.675%
ExxonMobil	19%
Husky Oil	13%
Statoil ASA	15%
Murphy	10.475%
Mosbacher	3.85%
Chevron	1%

The Terra Nova field was discovered by Petro-Canada (now Suncor Energy) in 1984 about 35 kilometers southeast of Hibernia, in about 90 meters of water. The discovery well, Terra Nova K-08, located about 350 kilometers southeast of St. John's, NL flow-tested 10,000 barrels of oil per day from the Jeanne d'Arc reservoir. Five subsequent successful delineation wells tested at rates ranging from 5,000 to 25,000 bopd.

The field is being developed using a Floating Production Storage and Offloading (FPSO) vessel and first oil was produced on January 20, 2002. The Terra Nova FPSO was the first of its kind to be used in North America and included the largest disconnectable turret mooring system in the world. The vessel is double hulled with oil cargo tanks capable of holding up to 960,000 barrels of oil.

The latest recoverable reserve estimate for the Terra Nova field, released in 2009, includes 419 million barrels of oil, 53 billion cubic feet of natural gas and 4 million barrels of natural gas liquids. The approved production rate for the Terra Nova FPSO is 180,000 barrels of oil per day.

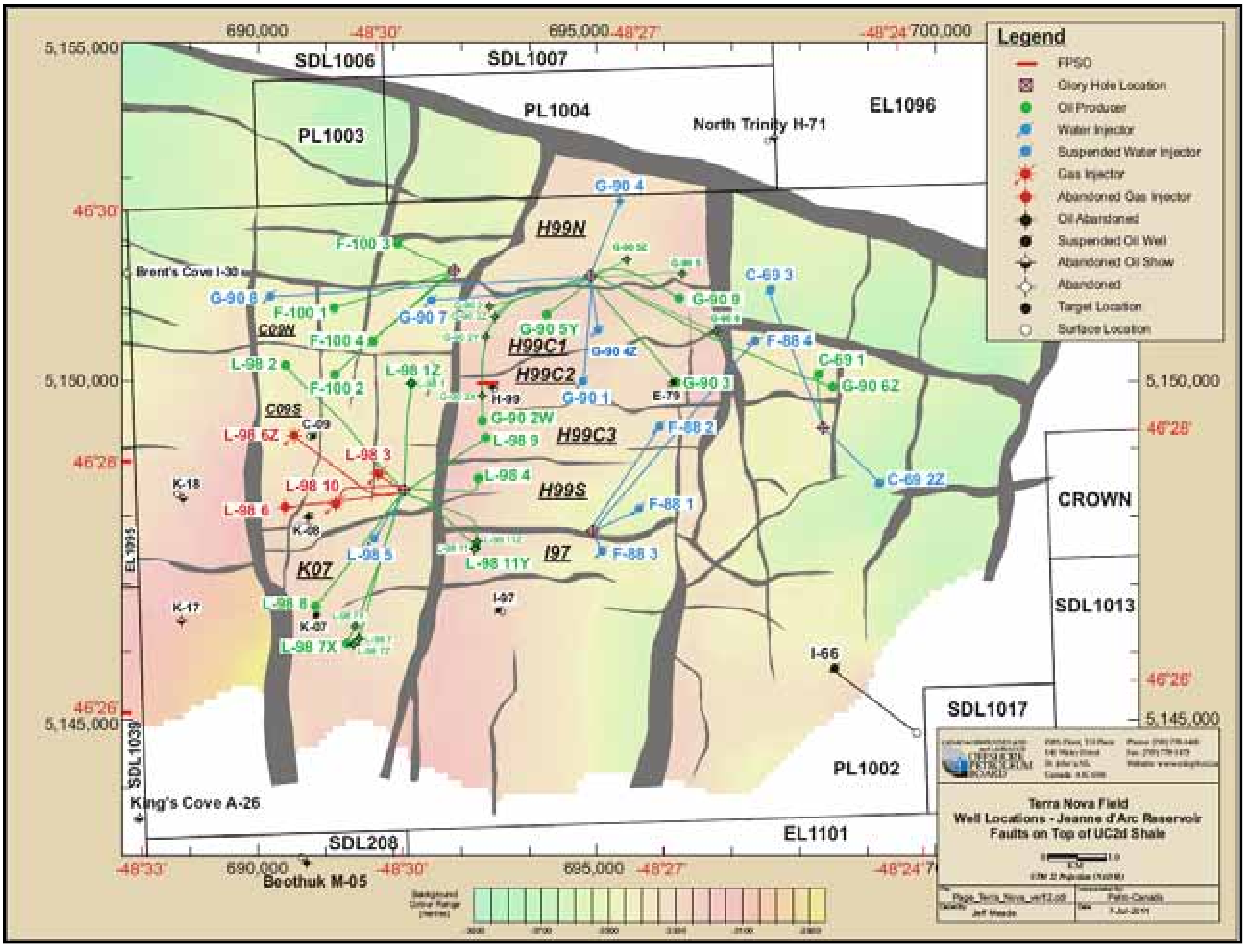
Terra Nova FPSO

As of December 31, 2011, Terra Nova was operating with a total of 22 development wells as shown in Figure #5 on page 15. These consist of 10 oil producers, 9 water injectors and 3 gas injectors. During 2011 the field produced 15.7 million barrels of oil equating to a daily production of 43,120 bopd. Cumulative field production to the end of 2011 was 327.1 million barrels of oil which represents 78.1% of the recoverable reserve estimate.

Production was anticipated to be lower in 2011 due to natural production declines but was further affected by the discovery of hydrogen sulfide (sour gas) late in 2010. The sour gas issue required the shut in of affected producing wells and also other wells that shared common flowlines back to the FPSO. To mitigate the production decline, Suncor deferred planned major repairs on the swivel in the ship's turret which was originally scheduled in 2011. It also replaced some flowlines in conjunction with the 2011 maintenance turnaround to enable some shut-in production wells to be restarted . The end result was a production decline of approximately 10 million barrels of oil over levels achieved in 2010.

Suncor have announced that Terra Nova FPSO will come off location in 2012 for an extended maintenance turnaround at the Marystown Shipyard, located on the south coast of Newfoundland, to perform regular maintenance, repair the swivel, install equipment to address the sour gas problem and replace other affected flowlines and risers. The shut-in is expected to last 147 days and will result in further deferred oil production in 2012.

Figure #5 - Terra Nova Field Well Locations



2.3 White Rose Field

White Rose Project - Ownership	
Husky Energy	72.50 %
Suncor	27.50 %

In 1984 the White Rose field was discovered by Husky Energy by drilling the White Rose N-22 exploration well. The discovery well tested at 900 barrels of oil per day, 25 million cubic feet of natural gas and 840 barrels per day of condensate. The field consists of one principal reservoir, the Ben Nevis/Avalon, and is located 350 kilometers southeast of St. John's, NL in the Jeanne d'Arc Basin. Similar to the Terra Nova field, the White Rose field is being developed using a FPSO. The White Rose FPSO, named the Sea Rose, has a storage capacity of 940,000 barrels of oil and an approved production rate of 137,000 barrels of oil per day.

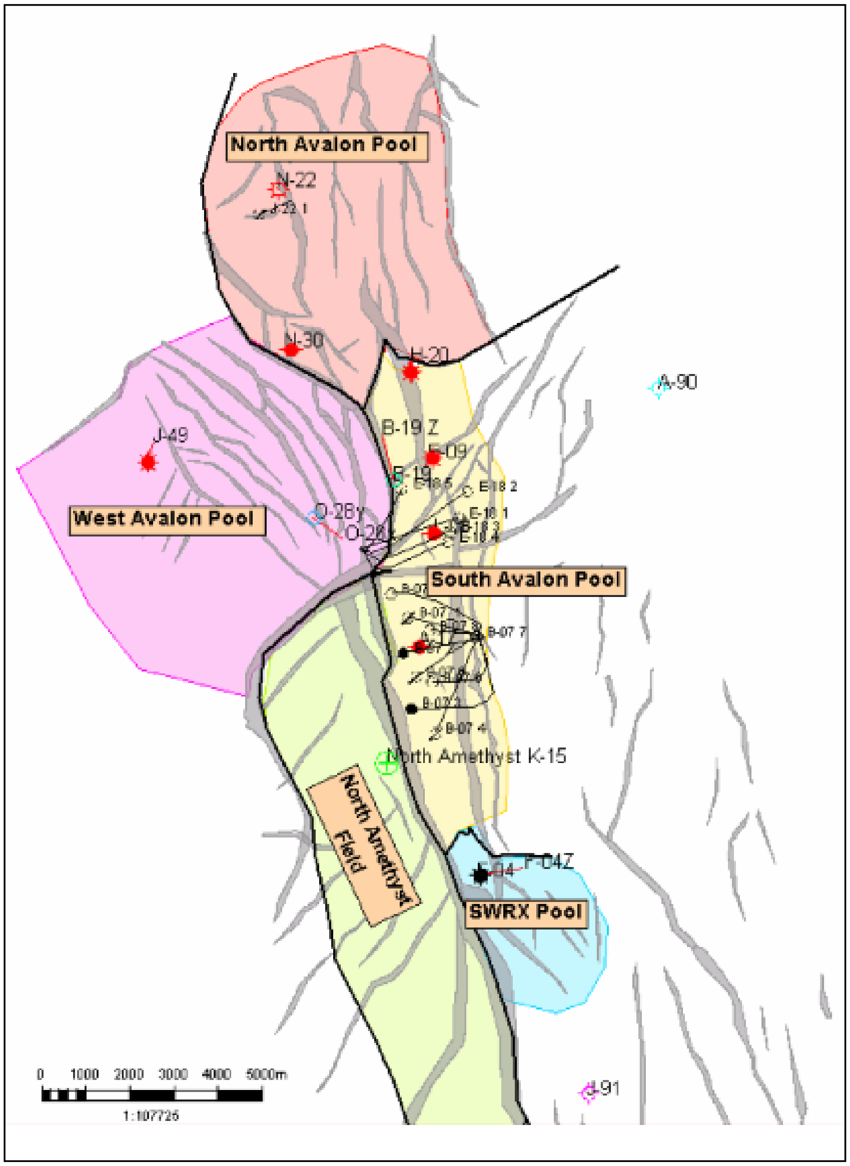
The C-NLOPB has assigned recoverable reserve/resource estimates for the field at 305 million barrels of oil, 3.02 trillion cubic feet of natural gas and 96 million barrels of natural gas liquids. These estimates include reserves/resources contained in the main White Rose field (South Avalon Pool), the South White Rose Extension (SWRX) Pool, the West Avalon Pool and North Avalon Pool. Figure 6 on page 17 shows the location of the various pools. These estimates however do not include recoverable resource estimates of 68 million barrels of oil and 315 million cubic feet of natural gas located in the North Amethyst Field which is adjacent to the White Rose Field and discussed in more detail in Section 2.4 of this report.

White Rose FPSO 'Sea Rose'

In 2010 the C-NLOPB approved a development plan amendment for the White Rose field to allow development of the West White Rose area. This amendment proposed a two well pilot scheme in the West Avalon Pool to further assess the viability and feasibility of a full field development in this area. See Section 2.3.1 on Page 19 for more details on this development.

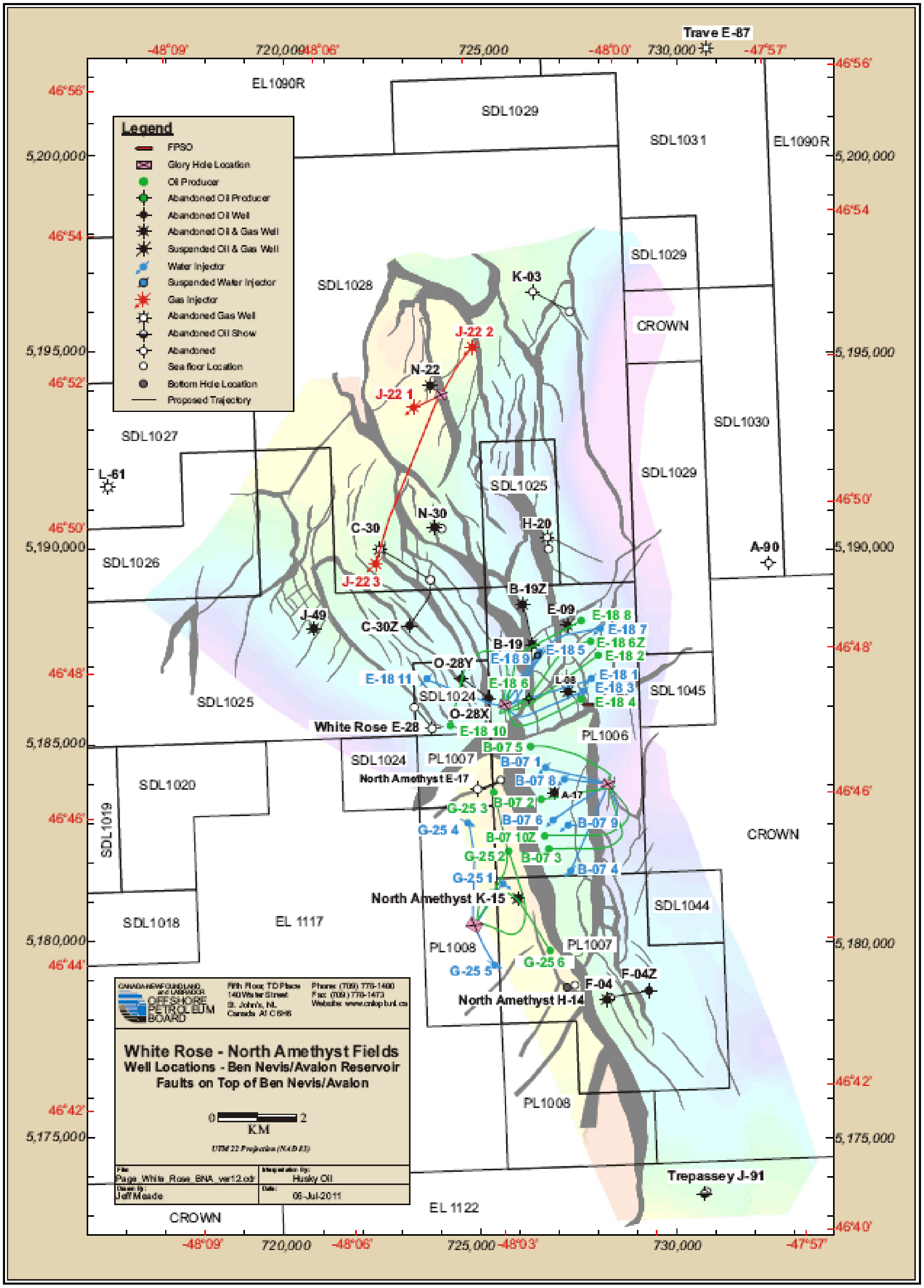
First oil was produced at the White Rose field on November 15, 2005 and the total cumulative production was 165.5 million barrels of oil as of December 31, 2011. This represents 54.2% of the current recoverable reserve/resource estimate. In 2011 production at the White Rose field (including the West White Rose area) totalled 12.7 million barrels of oil which equated to an average daily production of 34,800 barrels of oil per day. The field is being developed utilizing 22 development wells consisting of 9 production, 10 water injectors and 3 gas injectors as shown in Figure #7 on page 18. Production at the White Rose field is also expected to be reduced in 2012 as the Sea Rose FPSO is scheduled to come off location and travel to a dry dock for a major turnaround. Work planned during the maintenance shutdown will include repairs and enhancements to the vessel's propulsion system. Husky have estimated that the turnaround will last approximately 125 days affecting production at White Rose, West White Rose and North Amethyst fields.

Figure #6 - White Rose Development Area



Late in 2011 Husky issued an expression of interest for front end engineering and design (FEED) for a concrete gravity based wellhead platform to be located west of the White Rose FPSO. The wellhead platform would be capable of drilling exploration and production wells as well as pumping oil to the Sea Rose FPSO. The wellhead platform would replace the mobile offshore drilling units currently being used. Four companies have responded to the expression of interest and a decision on whether to proceed is expected to be announced early in 2012.

Figure #7 - White Rose Field Well Locations



2.3.1 West White Rose

West White Rose Project - Ownership	
Husky Energy	68.875%
Suncor	26.125%
Nalcor Energy	5.0%

Development of the West White Rose portion of the field has been under analysis since 2001. This portion of the field is part of the main Ben Nevis/Avalon reservoir and contained within Significant Discovery License 1047. In 2010 a development plan amendment was submitted and approved by the C-NLOPB allowing for the drilling of a two well pilot scheme at West White Rose to further assess the viability and feasibility of field development. The first development well (E-18 10) was spud on April 23, 2010 by the drilling rig, Henry Goodrich, and commenced production on September 5, 2011. As of December 31, 2011 the well had produced a total of 663,044 barrels of oil. The second well, water injector E-18 11, was in the completion phase late in November, 2011 when a supply vessel collided with the drilling rig GSF Grand Banks causing damage to the rig. The well was cemented and cased at the time and has been suspended. The rig was relocated to the Irving Shipyard facility in Nova Scotia to undergo repairs and also to complete its mandatory five year survey for recertification. It is estimated that the rig will be in the yard for 60 days before returning to the field.

The initial estimated cost for the West White Rose pilot scheme was $250 million CAD which included a $130 million CAD drilling program and $120 million CAD for subsea infrastructure. The C-NLOPB have assigned a resource estimate for the West White Rose pool at 40 million barrels of oil. This amount is included in the total reserve/resource estimate for the White Rose Field, as detailed in Section 2.3, however this figure could be revised once the results of the pilot scheme are known.

2.3.2 South White Rose Extension

A development plan amendment was approved by the C-NLOPB in 2007 for the South White Rose Extension (SWRX) contained within Significant Discovery Licenses 1043 and 1044. The plan called for a subsea tie-back to the SeaRose FPSO through the existing southern glory hole as well as a new glory hole to be constructed approximately 4 kilometers further south. Although approval was granted by the C-NLOPB, the co-venture partners have not yet proceeded with the development.

The C-NLOPB have assigned a resource estimate for the South White Rose Extension of 23 million barrels of oil which is also included in the total reserve/resource estimate for White Rose as detailed in Section 2.3.

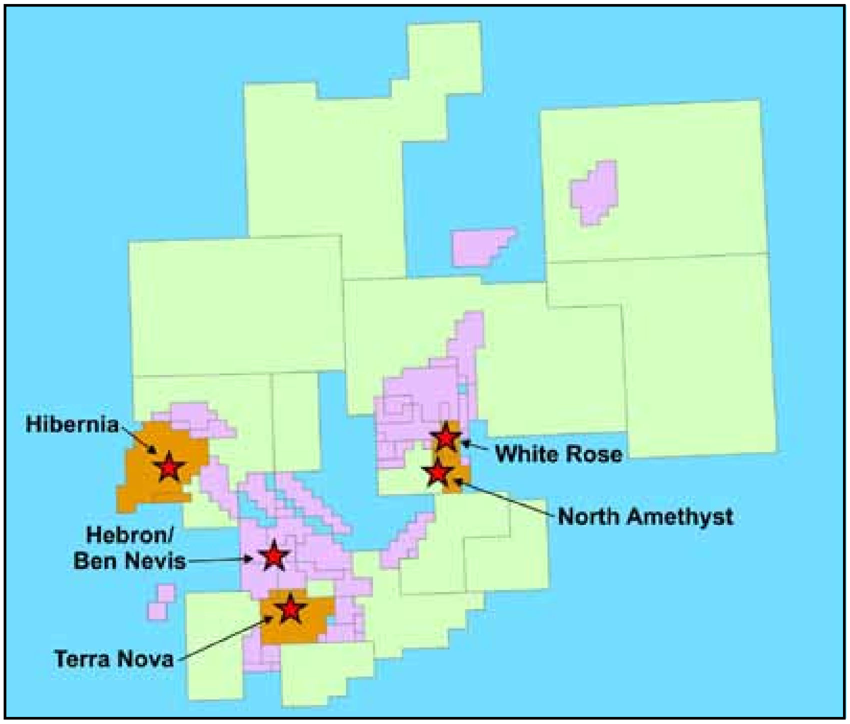
2.4 North Amethyst Field

North Amethyst Project - Ownership	
Husky Energy	68.875 %
Suncor	26.125 %
Nalcor Energy	5.0 %

In 2008 the co-venture partners; Husky Energy and Petro-Canada (now Suncor Energy), and the Province of Newfoundland and Labrador, through Nalcor Energy - Oil and Gas , signed a development agreement for lands surrounding the original White Rose development. As part of this agreement, Nalcor agreed to purchase a 5% equity stake in the project at a cost of $30 million CAD, subject to a confirmation of reserve estimates. Note that the terms of the original White Rose development remain unchanged.

The North Amethyst field was the first of the satellite pools to be developed in the Jeanne d'Arc Basin. It was identified by exploratory drilling in 2006 and the C-NLOPB reports recoverable reserve/resource estimates of 68 million barrels of oil and 315 billion cubic feet of natural gas in the Ben Nevis/Avalon Formation. In 2009 Husky Energy announced that additional resources were discovered at North Amethyst in the lower Hibernia Formation, totalling approximately 60 million barrels of original oil in place. Further details on these new resources have not been released and the C-NLOPB have not yet completed an analysis of the new discovery for resource estimates.

Figure #8 - Jeanne d'Arc Basin

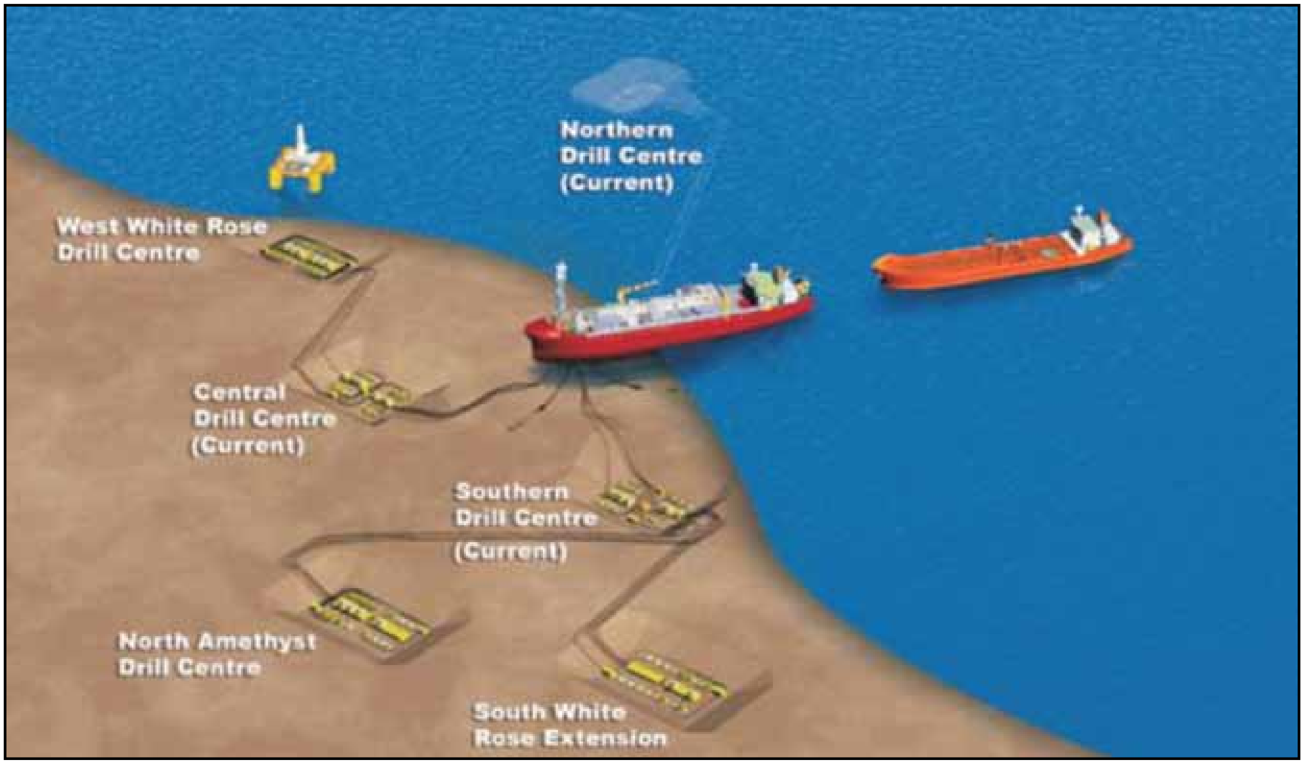


The initial estimated capital cost to develop North Amethyst was $1.5 billion CAD including $705 million CAD for drilling and completions and $587 million CAD for subsea development. Nine wells were planned for the development including four oil producers and five water injectors. Completion and installation of the subsea components and modifications to the existing Sea Rose FPSO to allow for production from North Amethyst were completed in 2010.

Flexible underwater flowlines connect the field to the SeaRose FPSO which is located approximately 6 kilometers away. Initial production from North Amethyst occurred on May 31, 2010 from the oil producer well G-25 2.

As of December 31, 2011 North Amethyst was operating with six development wells consisting of 3 oil producers and 3 water injectors. Total oil production in 2011 was 12.5 million barrels of oil giving an average daily production of 34,190 bopd. Cumulative production to

Figure #9 - North Amethyst Tie Back Development via Sea Rose FPSO



December 31, 2011 was 16.2 million barrels representing 23.8% of the current total recoverable reserve estimate.

Production from North Amethyst was an important milestone as it represented production from Canada's first offshore satellite tieback project. The additional production from North Amethyst will slow the decline in production at the SeaRose FPSO and extend its life of field development.

2.5 Hebron/Ben Nevis Field

Hebron/Ben Nevis Project Ownership	
ExxonMobil	36.0429%
Chevron	26.628%
Suncor	22.7289%
Statoil ASA	9.7002%
Nalcor Energy	4.9%

The Hebron field was discovered in 1981 when the Mobil et al Hebron I-13 discovery well recovered hydrocarbons from five intervals with a combined flow rate of 9,070 barrels of oil per day. The field is located in the Jeanne d'Arc Basin approximately 31 kilometers southeast of Hibernia, 8 kilometers north of Terra Nova and 46 kilometers southwest of White Rose. The water depth in the area ranges from 88 to 102 meters of water. The adjacent Ben Nevis and West Ben Nevis fields that lie to the northeast of Hebron were discovered in 1980 and 1984 respectively. See Figure #8 on page 20 that details field locations.

The C-NLOPB have assigned a reserve estimate for the Hebron field at 581 million barrels of recoverable oil. Estimates for the Ben Nevis and West Ben Nevis discoveries by the C-NLOPB include an additional 150 million barrels of oil, 429 billion cubic feet of natural gas and 30 million barrels of natural gas liquids.

Formal agreements were signed with the co-venture partners and the Government of Newfoundland and Labrador to develop the Hebron offshore project on August 20, 2008. As part of the agreement Nalcor Energy - Oil and Gas purchased a 4.9% stake in the project at a cost of $110 million CAD. It was also agreed that Nalcor would pay a proportionate share of the project development costs and in return would received a similar share of production.

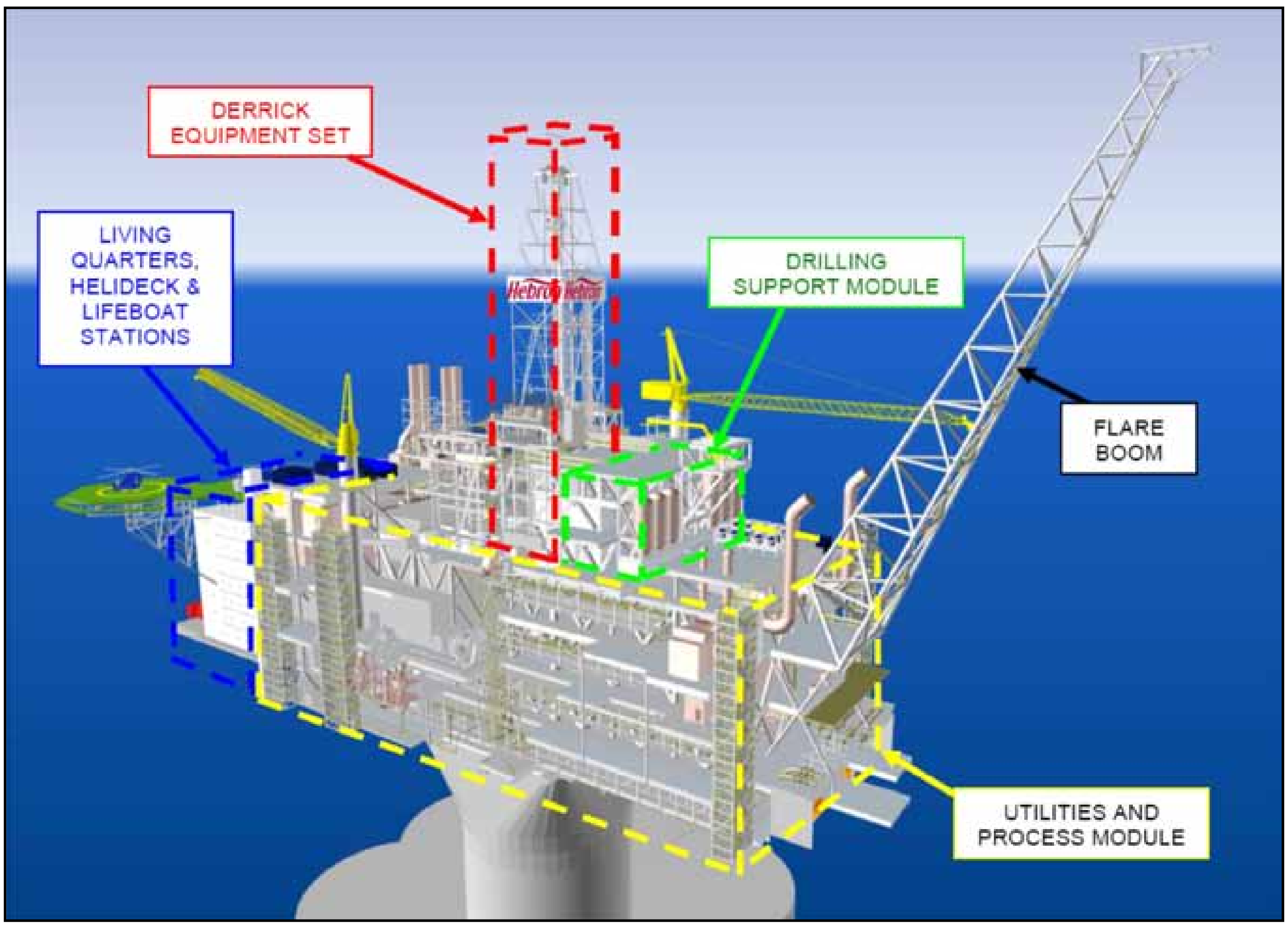
The Development Plan Application for the project was submitted to the C-NLOPB in April, 2011 and the Public Review consultations were completed late in 2011. The Commissioner's independent report is scheduled to be filed with the C-NLOPB by the end of February, 2012.

The Hebron Development Plan outlines producing oil reserves from the Hebron field initially, with the injection of the surplus gas into the West Ben Nevis area. The reserves of the adjacent Ben Nevis and West Ben Nevis fields are anticipated to be produced once the Hebron development is operational. Hebron will be developed using a gravity based structure (GBS) similar to, albeit on a smaller scale, to the Hibernia GBS. Estimated capital costs for the Hebron project are $8.3 billion CAD including $1.9 billion CAD allocated for drilling operations. Project sanctioning is expected to occur in mid to late 2012. Construction of the GBS is expected to commence shortly thereafter at the Bull Arm, NL construction site, with first oil expected in 2017. Additional development and related capital costs will be necessary to access the Ben Nevis and West Ben Nevis fields.

The Hebron development's project office was opened in St. John's, NL in 2009. On September 1, 2010 ExxonMobil, the project operator, awarded the Topsides Front End Engineering and Design (FEED) contract to WorleyParsons Canada Services Ltd. The contract also has an option, at ExxonMobil's discretion, for WorleyParsons to provide subsequent Engineering, Procurement and Construction (EPC) services. WorleyParsons estimates the entire FEED/EPC contract to be worth US $85 million over five years.

Construction plans call for the topside facility to be assembled from seven individual components. They include the utilities and and process module, the drilling support module, the drilling equipment set, the living quarters, the helideck, the flare boom and the lifeboat stations. Under the terms of the development agreement with the Government of Newfoundland and Labrador, it was stipulated that the helideck, the life boat station and the flare

Figure #10 - Proposed Hebron Development



boom would be built in province. It was also agreed that the living quarters, the drilling support module and the drilling equipment set would be built in the province if there is suffiicient labour and capacity at local fabrication yards. Due to the size of the utilities and process module it was agreed that an International Expression of Interest (EOI) would be issued for its construction.

During 2011 it was announced that the drilling support module would be built at the Kiewit Offshore facilities in Marystown and Cow Head, NL. Local EOIs were issued in 2011 for the construction of the living quarters and the drilling equipment set. Awarding of these contracts is expected early in 2012. The International EOI for the utlities and process module was also issued in 2011 and Dockside's heavy lift vessel, Blue Marlin, has been contracted to transport the module when completed to the Bull Arm construction site for integration and final assembly.

On November 9, 2010 ExxonMobil announced the awarding of the GBS FEED contract to Kiewit-Aker Contractors. Kiewit-Aker Contractors was a 50-50 joint venture between USA based Peter Kiewit Infrastructure and Norwegian based Aker Solutions. Peter Kiewit Infrastructure is affiliated with Peter Kiewit Sons' Inc. which owns the local Marystown Shipyard and the Cow Head fabrication yard. In 2011 Aker Solutions was reorganized and the responsibility for GBS development was transferred to a new entity, Kvaerner ASA. As a result, the partnership responsible for the Hebron GBS FEED was changed to Kiewit-Kvaerner Contractors (KKC). The FEED contract, valued at US $140 million, also includes site preparation at the Bull Arm fabrication site. Once again, at ExxonMobil's discretion, the contract includes an option to extend the agreement to cover EPC services for the GBS.

Work to be undertaken by KKC at the Bull Arm construction site includes refurbishing existing buildings, upgrading utilities and roads, building a work camp to accomodate 2,000 people, installing concrete batch plants and rebuilding the drydock facilities. Work commenced on these projects in 2011 and will continue into 2012.

2.6 Garden Hill South

Garden Hill South is located onshore western Newfoundland on the Port au Port Peninsula. PDI Production Inc. (PDIP), a subsidiary of Enegi Oil Plc, is the operator of the production lease issued by the Province of Newfoundland and Labrador.

Figure #11 - Location of Port au Port Peninsula

Activity at the Garden Hill site commenced in September, 1994 when Hunt/Pan Canadian drilled the Port au Port (PAP) #1 well. The well encountered two hydrocarbon bearing intervals within Aguathuna Formation dolostones with flow rates of 1,528 and 1,742 barrels of 51 degree API oil, and, 2.6 and 2.3 million cubic feet of natural gas per day.

Several sidetrack wells have been drilled at the PAP #1 well and in early 2009 PAP# 1 Sidetrack #3 was shut in for an extended period of time for a pressure build up test. At the time of shut-in, long term commercial production was deemed sub-economic by PDIP. Dragon Lance Management (DLMC), under a farm in arrangement, completed workover programs on Sidetrack #3 in 2010 which were intended to significantly improve recovery rates and also connectivity between the wellbore and the reservoir. In mid 2011 PDIP announced that they were terminating the farm in agreement with DLMC as programs outlined in the agreement were not completed within the agreed upon timeframes.

PDIP, having full control of the license, hired Schlumberger late in 2011 for the second phase of the workover program. Schlumberger have completed a portion of the work and plan to return in 2012 to advance the project. In 2011 a total of 348 barrels of oil were produced bringing the total cumulative production at Garden Hill to 35,385 barrels of oil.

3.0 Regional Activity Update

3.1 East Coast Offshore - North Grand Banks

Resource Opportunity - 2011 Call for Bids

There was one Call for Bids completed in 2011 for two parcels of land in the Flemish Pass/ North Central Ridge area. With total bids of $347,774,664 CAD (as detailed in the charts below), the successful group was led by Statoil Canada Ltd with co-venture partners Chevron Canada and Repsol E&P Canada. The criteria used for evaluation of the bids was the highest total work expenditure commitment submitted. Exploration licenses will be issued for these land parcels early in 2012 when all terms and conditions are met.

Call for Bids NL11-02 (Flemish Pass/North Central Ridge)	
Parcel 1 (247,016 ha)	Bid amount - $202,171,394
Statoil Canada Ltd.	50%
Chevron Canada Limited	40%
Repsol E&P Canada Ltd.	10%
Parcel 2 (186,780 ha)	Bid amount - $145,603,270
Statoil Canada Ltd.	50%
Chevron Canada Limited	40%
Repsol E&P Canada Ltd.	10%

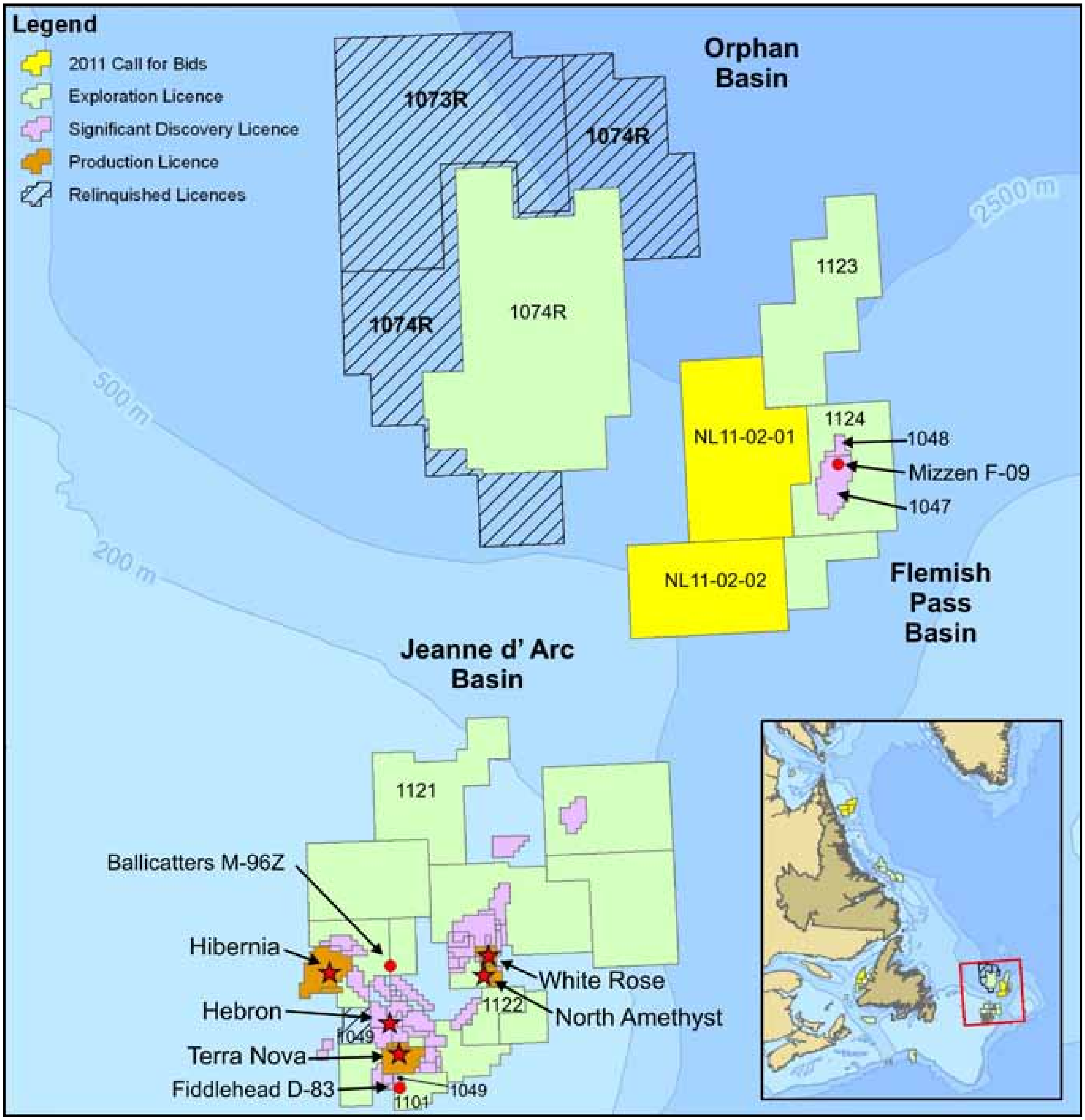
Exploration Activity - Drilling Programs

In the Jeanne d'Arc Basin, Suncor Energy, utilizing the drilling rig Henry Goodrich, completed their Ballicatters M-96Z sidetrack exploration well on May 6, 2011. The well was drilled in a water depth of 101 metres to a total depth of 4212 metres on land that straddles Exploration Licenses 1092 and 1113. While the well was classified as a "tight hole" and detailed drilling results have not been released, Suncor have announced that hydrocarbons were discovered. Further analysis of the drilling results is ongoing.

Also in the Jeanne d'Arc Basin, Statoil drilled a delineation well at their Mizzen discovery. The Henry Goodrich spud the Mizzen F-09 well on Significant Discovery License 1047 on July 29, 2011. The well was drilled in a water depth of 1067 metres to a total depth of 3762 metres. Information obtained will be used by Statoil and co-venture partner Husky Energy to help determine the size of the Mizzen discovery.

Also using the drilling rig, the Henry Goodrich, Statoil spud an exploration well on October 4, 2011 on their Fiddlehead prospect in the Jeanne d'Arc Basin. The well, Fiddlehead D-83, was drilled on Exploration License 1101 in a water depth of 93 metres to a total depth of 1870 metres. The well was completed on November 18, 2011 and no information on drilling results have been released.

Figure #12 - East Coast Regional Map



Geoscience Programs

Two major seismic programs were completed in the Flemish Pass Basin in 2011. Chevron Canada, utlizing the WG Tasman, collected 6122 line kilometers of 3D data and Statoil Canada, utilizing the WG Amundsen, collected 494 line kilometers of 2D and 1786 square kilometers of 3D data.

In the Jeanne d'Arc Basin two wellsite surveys were completed by Husky Energy utilizing the M/V Maersk Chignecto in anticipation of potential future drilling programs.

Licensing – Land Rights

Four new Exploration Licenses were issued by the C-NLOPB in 2011 to the successful bidders from the 2010 Call for Bids. Exploration Licenses 1121 and 1122 were issued in the Jeanne d'Arc Basin, with Husky Energy as representative, and 1123 and 1124 were issued in the Flemish Pass Basin, with Statoil Canada as the representative.

Exploration licenses 1073R and 1074R in the Orphan basin were consolidated in 2011. The end result was the surrender of lands covered under 1073R and a partial surrender of lands under 1074R. Lands held post consolidation are shown in Figure 12 on page 27.

Exploration License 1094, held by Husky Energy, was at the end of the term of Period 1 and the land located in the Jeanne d'Arc Basin has been returned to crown reserve.

Significant Discovery Licenses (SDL) 1048 and 1049 were issued in 2011 to the co-venture partners, Statoil Canada and Husky Energy. SDL 1048 was issued as a result of their successful bid for a parcel of land in the Flemish Pass Basin associated with Call for Bids NL 10-03. The awarding of SDL 1049 relates back to the drilling of the King's Cove A-26 discovery well in 2006. At the time of declaring the King's Cove significant discovery area it was determined that a portion of the land fell outside the boundaries of the applicable exploration license that the well was drilled on. As a result, only the land held within the exploration license area could be awarded a Significant Discovery License. In the 2006 licensing round, the parcel of land that was awarded to Statoil and Husky under Exploration License 1101 contained the remaining portion of the King's Cove discovery area. In 2011 the co-venturers partners applied for, and were granted, SDL1049 by the C-NLOPB as a result of the previously drilled King's Cove A-26 discovery well.

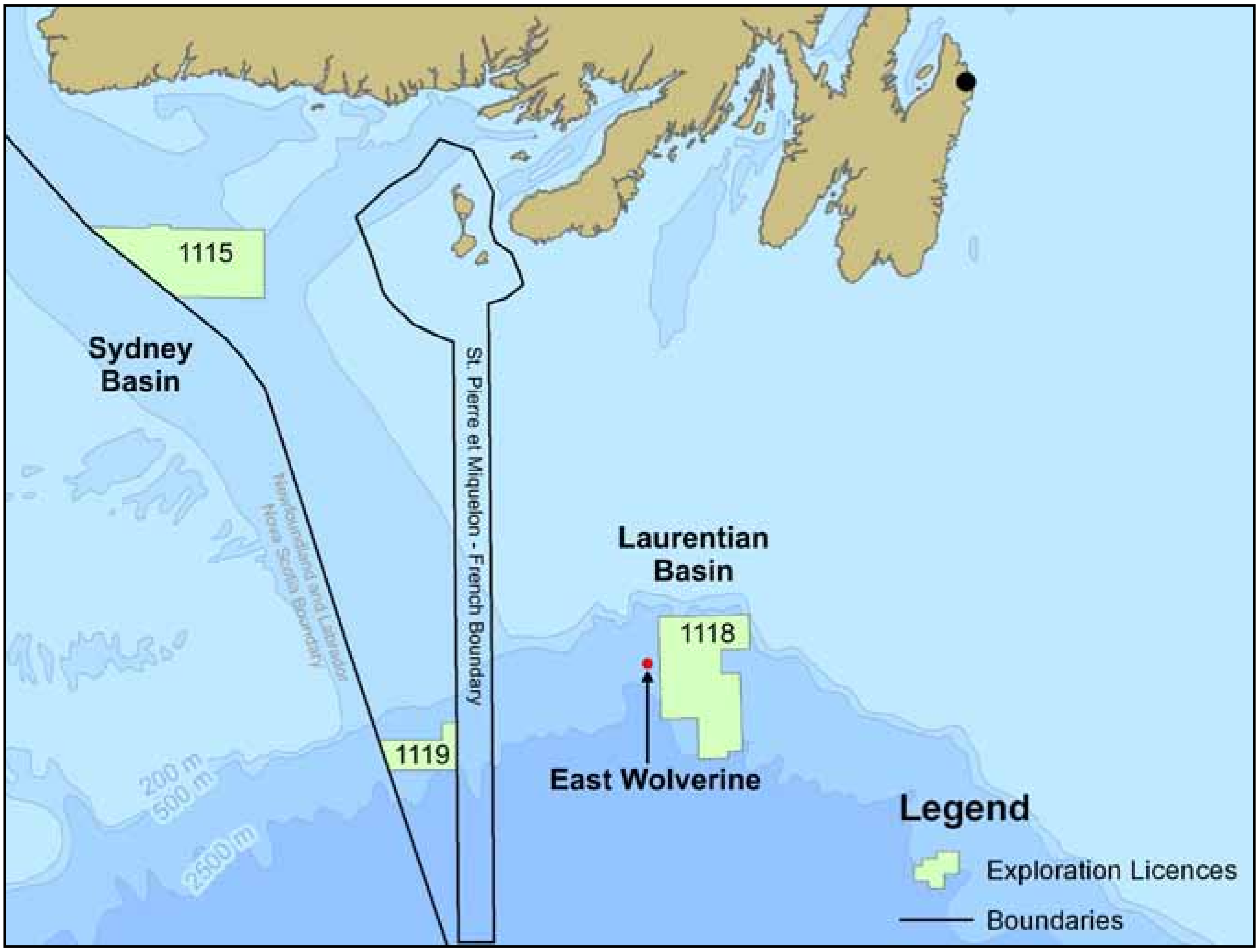
3.2 South Coast Offshore

Exploration Activity

Husky Energy is the owner of EL 1115 in the Sydney Basin and co-venture partners ConocoPhillips Canada and BHP Billiton Petroleum hold the rights to EL1118 and EL 1119 in the Laurentian Basin. Husky acquired their rights in the 2009 licencing round whereas ConocoPhillips Canada and BHP Billiton Petroleum acquired theirs in the 2010 licensing round.

In 2010 Husky Energy completed an extensive 2D seismic over their parcel and analysis of the results continued in 2011. ConocoPhillips Canada and BHP Billiton Petroleum completed drilling the East Wolverine G-37 exploration well in the Laurentian Basin in 2010. The land parcel that the well was drilled on has since been relinquished and the co-venture partners have not announced well results or further exploration plans for the area around ELs 1118 and 1119.

Figure #13 - South Coast Regional Map



3.3 West Coast Onshore and Offshore

Onshore - Exploration and Land Rights Licensing

Parsons Pond

Nalcor Energy – Oil and Gas, the Province's provincially owned energy company is the major interest holder (67%) in Exploration Permits (EPs) 03-102 and 03-103 in the Parson's Pond area as shown in Figure #14 on page 31. In 2010 the company commenced a three well exploration program drilling the Seamus #1 and Finnegan #1 wells. Both wells encountered gas bearing zones and testing was performed on the Seamus #1 well. Interpretation and analysis of the test results are ongoing. In 2011 Nalcor announced that they would not be proceeding with drilling the third well, Darcy #1.

While Nalcor originally held majority interest in three permits, one permit (EP 03-101) was at the end of its term and the associated land reverted back to crown reserve.

Bay St. George Area

Vulcan Minerals Inc, owner's of EPs 96-105, 03-106 and 03-107, conducted a $4.0 million exploration program over its Flat Bay oil prospect in 2011. The purpose of the program was to help quantify the size of the oil pool, find natural fracturing in the rocks and test for oil deposits at deeper depths. The program consisted of a six hole coring program and 1673 metres of core was collected.

Analysis of the results is ongoing and will ultimately define the next steps in a petroleum resource and reserve assessment for the area. All work that Vulcan Minerals is completing in the Bay St. George area is being carried out pursuant to a 50/50 joint venture with Investcan Energy Corporation.

Deer Lake Area

Deer Lake Oil and Gas Inc. holds exploration permits EPs 93-103 and 03-105 in the Deer Lake Basin. It drilled a shallow exploration well, Werner Hatch #1, utilizing the Logan #44 drilling rig in 2010. The company announced early 2011 that it would be pursuing another well (Admiral's Rise #1) on EP 03-104 to validate that permit. The well was not drilled in 2011 before the end of the permit term and the associated lands reverted back to crown reserve.

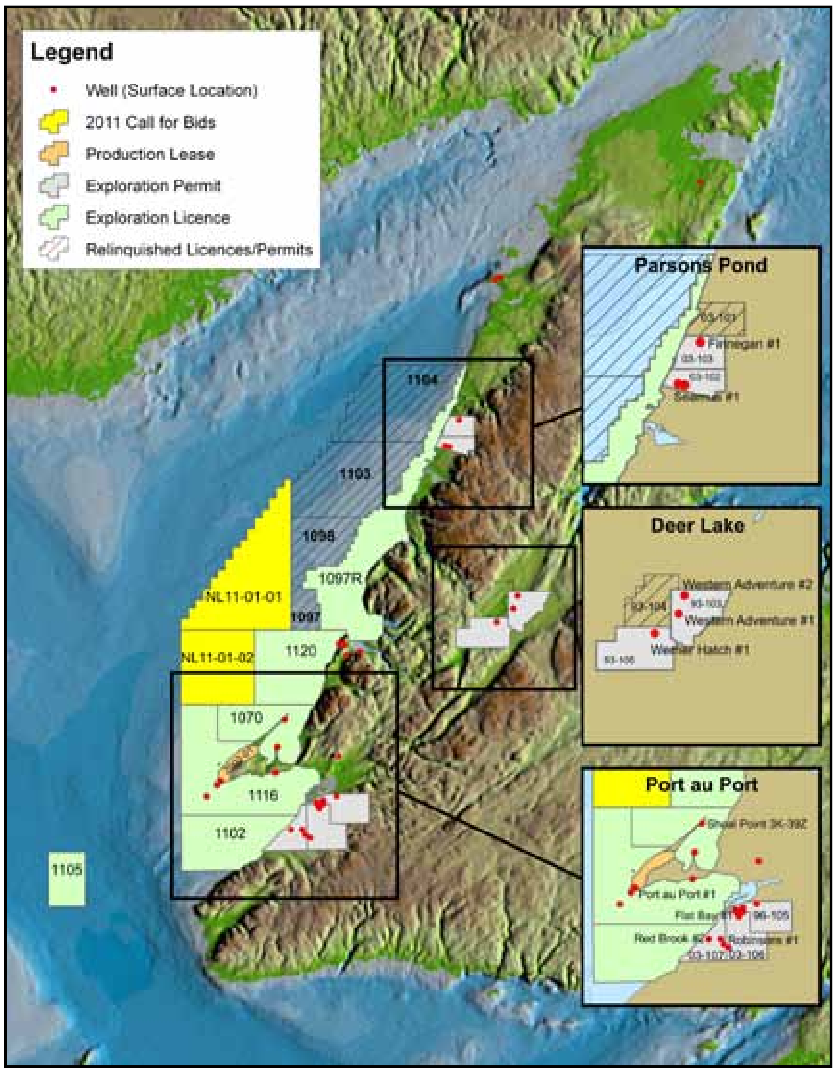
Offshore Resource Opportunity - 2011 Call for Bids

Ptarmigan Energy Inc. was the successful bidder on two parcels of land offshore western Newfoundland that were offered in the 2011 Call for Bids. Ptarmigan submitted bids in the amount of $501,000 CAD and $1,501,000 CAD on parcels offered under Call for Bids NL 11-01-01 and NL 11-01-02 respectively. Exploration licenses will be issued for these land parcels early in 2012 when all terms and conditions are finalized.

Offshore - Exploration Activity

Dragon Lance Management Corporation, on behalf of Shoal Point Energy, spud the onshore to offshore exploration well, Shoal Point 3K-39, utilizing the Nabors #112 drilling rig. Drilling commenced onshore on January 12, 2011 and entered the offshore area on February 18, 2011. The well was drilled to a total depth of 1745 metres targeting oil in the Green Point Formation on EL-1070. Data from logging operations and core sampling was completed over several intervals and the well was cased to 1711 metres. Due to well conditions, attempts to adequately flow test the well were not successful. Note that, among other requirements, an adequate flow test is required by the C-NLOPB to extend the term of the Exploration License from Period 1 to Period 2. The well was terminated on August 2, 2011 and Shoal Point Energy announced that they will proceed, subject to regulatory approval, to drill a side track exploration well to the base of the Green Point Formation. Plans for the new sidetrack, to be completed in 2012, call for a comprehensive well testing program.

Figure #14 - West Coast Regional Map



Also in 2011, Corridor Resources Limited filed a projection description with the C-NLOPB concerning its plans to drill an exploration well on its “Old Harry” prospect in the Gulf of St. Lawrence on EL1105. As part of its review, the C-NLOPB asked for, and received, public input into the proposed drilling program. Due to concerns raised about the potential for environmental damage as a result of an oil spill, the C-NLOPB referred the issue to the Federal Minister of Natural Resources. The Minister requested that the 2007 Strategic Environmental Assessment (SEA) for the Western Newfoundland Offshore Area be updated and that extensive public consultations be held. The C-NLOPB, in response to the Minister’s request, has formed a working committee to conduct the update to the SEA and appointed Mr. Bernard Richard to conduct the independent review. The C-NLOPB have indicated that the results of these two processes will need to be considered prior to a decision being made on Corridor’s drilling application.

Offshore - Land Rights Licensing

NWest Energy Corporation was granted a consolidation of its exploration licenses offshore western Newfoundland in 2011. Under the consolidation agreement ELs 1097, 1098, 1103 and 1104 were consolidated into EL 1097R. Under the terms of the consolidation, NWest relinquished rights to 456,711 hectares. This leaves them with a balance of 202,838 hectares which is underlain by the Green Point Formation. The new expiry date for Period 1 applicable under the new EL1097R is January 15, 2012, however, provisions are in place for a one year extension to the term with the filing of a drilling deposit.

Ptarmigan Energy Inc. acquired EL-1120 in the 2009 licensing round and in 2011 signed a Farm-In Agreement with Shoal Point Energy Ltd. for the shallow exploration rights on the parcel. Under the terms of the agreement, Shoal Point Energy has the right to earn a working interest in the shallow rights with a cash payment in the amount of $1.8 million CAD and the drilling of a test well in the Green Point formation prior to December 31, 2012. Further, pursuant to the terms of the Area of Mutual Interest Agreement between Shoal Point Energy and Canadian Imperial Venture Corporation, Canadian Imperial has advised that it will participate with Shoal Point in the Farm-in Agreement. After terms of the farm-in agreement are met, interest in the shallow rights of EL-1120 will be Shoal Point Energy - 48%, Canadian Imperial Venture Corp. 32% and Ptarmigan Energy - 20%.

3.4 Labrador Offshore

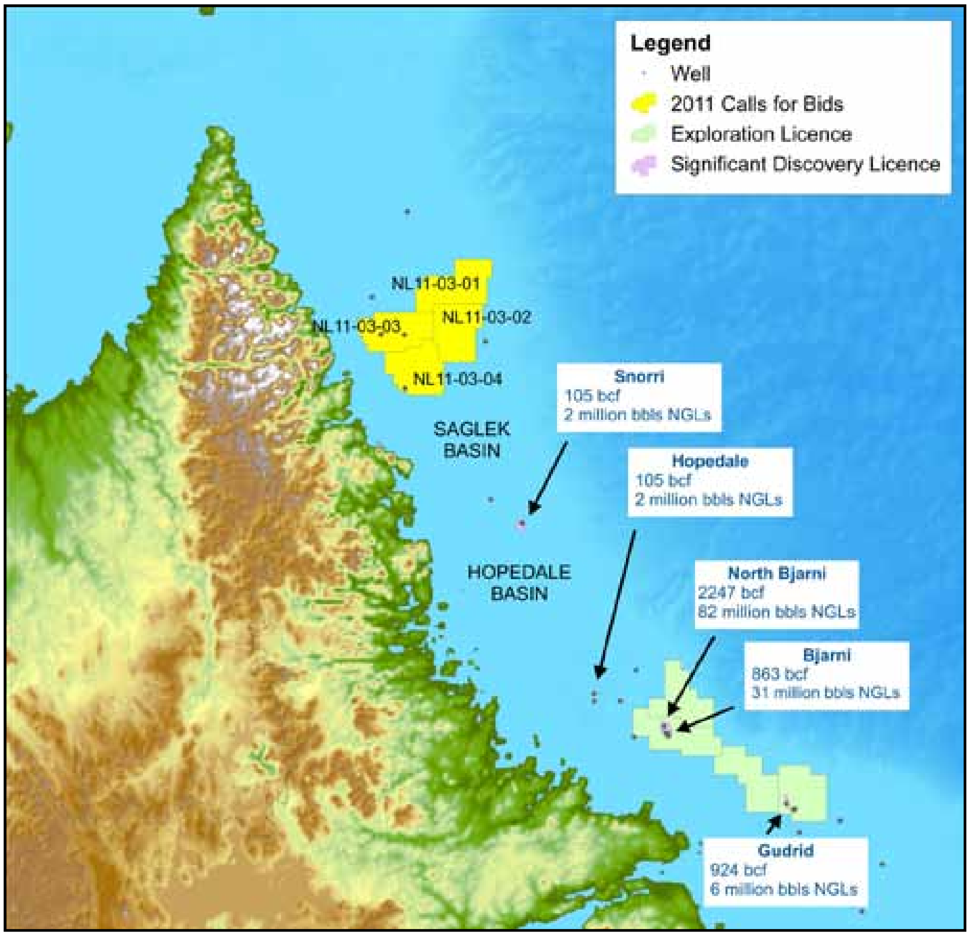
Resource Opportunity - 2011 Call for Bids

Four parcels of land were offered in the Saglek Basin in the 2011 offshore licensing round conducted by the C-NLOPB. Note that no bids were received on the land parcels and the land remains crown reserve.

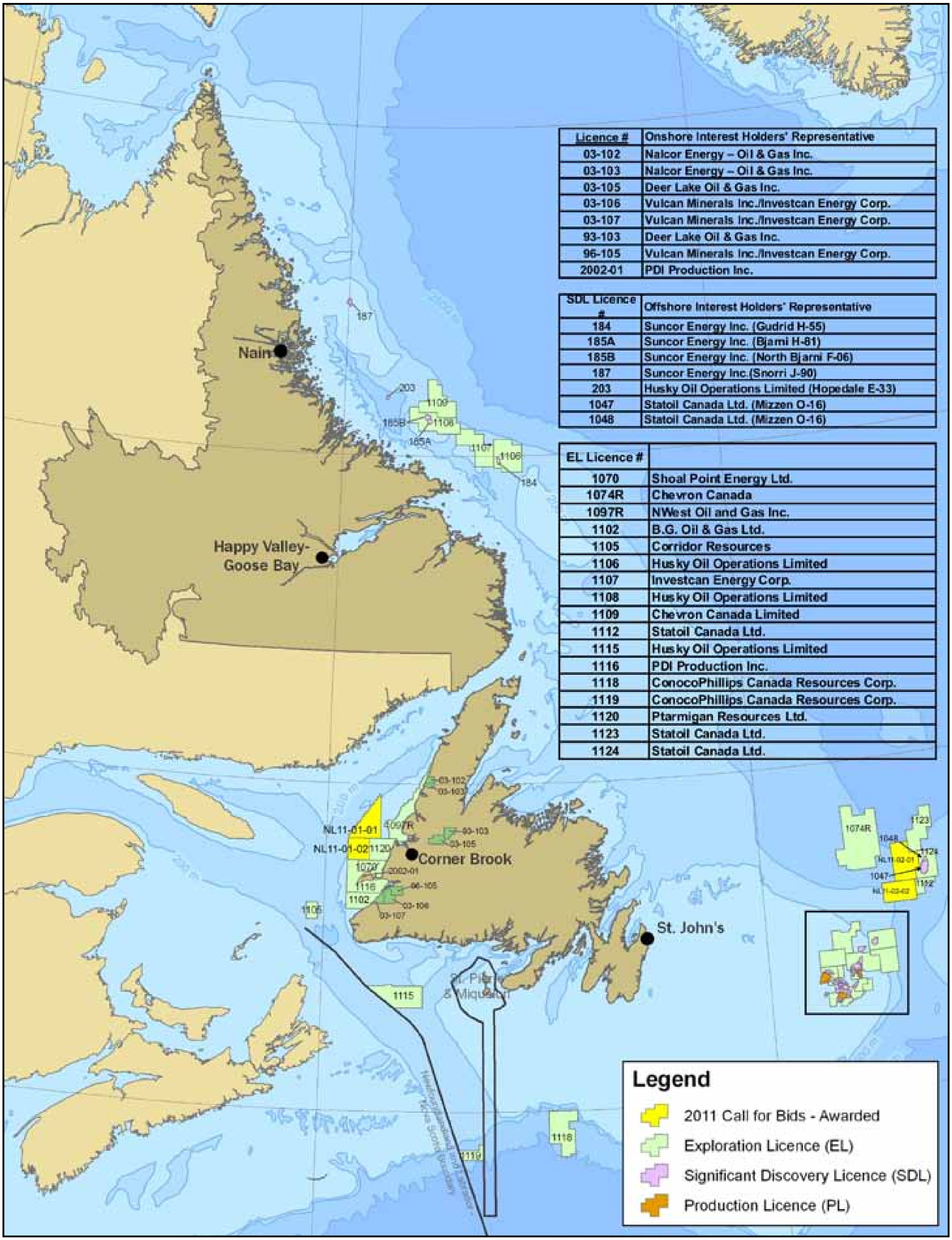
Geoscience Programs

In 2011 the TGS NOPEC Geophysical Company/Petroleum Geo-Services Inc. led consortium, Multi Klient Invest, announced they will be undertaking a major 22,000 kilometer offshore 2D survey in Newfoundland and Labrador in 2011. The program commenced offshore Labrador in the Saglek and Hopedale utilizing the MV Sanco Spirit (see cover picture). A total of 5144 kilometers of data was acquired and the company will return to Labrador in 2012 to complete that portion of the survey and then move to the East Coast - North Grand Banks region for the next phase of the program.

Figure #15 - Labrador Regional Map



Appendix A

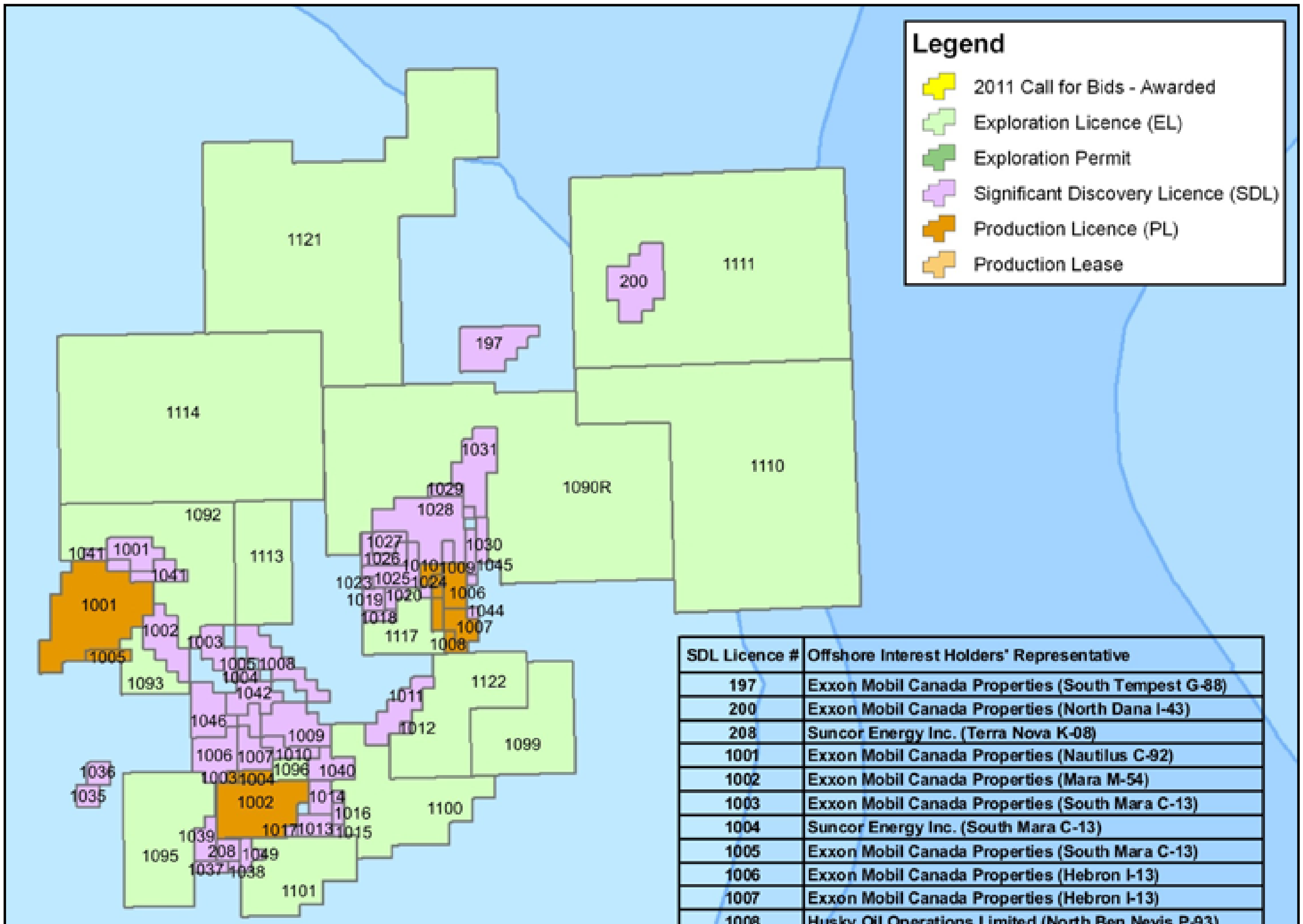


Licence #	Onshore Interest Holders' Representative
03-102	Nalcor Energy – Oil & Gas Inc.
03-103	Nalcor Energy – Oil & Gas Inc.
03-105	Deer Lake Oil & Gas Inc.
03-106	Vulcan Minerals Inc./Investcan Energy Corp.
03-107	Vulcan Minerals Inc./Investcan Energy Corp.
93-103	Deer Lake Oil & Gas Inc.
96-105	Vulcan Minerals Inc./Investcan Energy Corp.
2002-01	PDI Production Inc.

SDL Licence #	Offshore Interest Holders' Representative
184	Suncor Energy Inc. (Gudrid H-55)
185A	Suncor Energy Inc. (Bjarni H-81)
185B	Suncor Energy Inc. (North Bjarni F-06)
187	Suncor Energy Inc.(Snorri J-90)
203	Husky Oil Operations Limited (Hopedale E-33)
1047	Statoil Canada Ltd. (Mizzen O-16)
1048	Statoil Canada Ltd. (Mizzen O-16)

EL Licence #	
1070	Shoal Point Energy Ltd.
1074R	Chevron Canada
1097R	NWest Oil and Gas Inc.
1102	B.G. Oil & Gas Ltd.
1105	Corridor Resources
1106	Husky Oil Operations Limited
1107	Investcan Energy Corp.
1108	Husky Oil Operations Limited
1109	Chevron Canada Limited
1112	Statoil Canada Ltd.
1115	Husky Oil Operations Limited
1116	PDI Production Inc.
1118	ConocoPhillips Canada Resources Corp.
1119	ConocoPhillips Canada Resources Corp.
1120	Ptarmigan Resources Ltd.
1123	Statoil Canada Ltd.
1124	Statoil Canada Ltd.

Appendix B



EL Licence #	Interest Holders' Representative
1090R	Husky Oil Operations Limited
1092	Suncor Energy Inc.
1093	ExxonMobil Canada Properties
1095	Suncor Energy Inc.
1096	Husky Oil Operations Limited
1099	Husky Oil Operations Limited
1100	Statoil Canada Ltd.
1101	Statoil Canada Ltd.
1110	Husky Oil Operations Limited
1111	Husky Oil Operations Limited
1113	Suncor Energy Inc.
1114	Husky Oil Operations Limited
1117	Husky Oil Operations Limited
1121	Husky Oil Operations Limited
1122	Husky Oil Operations Limited

PL Licence #	Interest Holders' Representative
1001	ExxonMobil Canada Properties (Hibernia)
1002	Suncor Energy Inc. (Terra Nova)
1003	Suncor Energy Inc. (Terra Nova)
1004	Suncor Energy Inc. (Terra Nova)
1005	ExxonMobil Canada Properties (Hibernia)
1006	Husky Oil Operations Limited (White Rose)
1007	Husky Oil Operations Limited (White Rose)
1008	Husky Oil Operations Limited (North Amethyst)
1009	Husky Oil Operations Limited (White Rose)
1010	Husky Oil Operations Limited (White Rose)

SDL Licence #	Offshore Interest Holders' Representative
197	Exxon Mobil Canada Properties (South Tempest G-88)
200	Exxon Mobil Canada Properties (North Dana I-43)
208	Suncor Energy Inc. (Terra Nova K-08)
1001	Exxon Mobil Canada Properties (Nautilus C-92)
1002	Exxon Mobil Canada Properties (Mara M-54)
1003	Exxon Mobil Canada Properties (South Mara C-13)
1004	Suncor Energy Inc. (South Mara C-13)
1005	Exxon Mobil Canada Properties (South Mara C-13)
1006	Exxon Mobil Canada Properties (Hebron I-13)
1007	Exxon Mobil Canada Properties (Hebron I-13)
1008	Husky Oil Operations Limited (North Ben Nevis P-93)
1009	Exxon Mobil Canada Properties (Ben Nevis 1-45)
1010	Exxon Mobil Canada Properties (West Ben Nevis B-75)
1011	Husky Oil Operations Limited (Fortune G-57)
1012	Husky Oil Operations Limited (Fortune G-57)
1013	Imperial Oil Resources Ltd. (Springdale M-29)
1014	Imperial Oil Resources Ltd. (Springdale M-29)
1015	Imperial Oil Resources Ltd. (Springdale M-29)
1016	Imperial Oil Resources Ltd. (Springdale M-29)
1017	Husky Oil Operations Limited (Springdale M-29)
1018	Husky Oil Operations Limited (Whiterose N-22)
1019	Husky Oil Operations Limited (Whiterose N-22)
1020	Husky Oil Operations Limited (Whiterose N-22)
1023	Husky Oil Operations Limited (Whiterose N-22)
1024	Husky Oil Operations Limited (Whiterose N-22)
1025	Husky Oil Operations Limited (Whiterose N-22)
1026	Husky Oil Operations Limited (Whiterose N-22)
1027	Husky Oil Operations Limited (Whiterose N-22)
1028	Husky Oil Operations Limited (Whiterose N-22)
1029	Husky Oil Operations Limited (Whiterose N-22)
1030	Husky Oil Operations Limited (Whiterose N-22)
1031	Husky Oil Operations Limited (Trave E-87)
1035	Suncor Energy Inc. (East Rankin H-21)
1036	Suncor Energy Inc. (East Rankin H-21)
1037	Suncor Energy Inc. (King's Cove A-26)
1038	Suncor Energy Inc. (King's Cove A-26)
1039	Suncor Energy Inc. (King's Cove A-26)
1040	Statoil Canada Ltd. (West Bonne Bay C-23)
1041	Chevron Canada Ltd. (Nautilus)
1042	Husky Oil Operations Limited (Ben Nevis I-45)
1044	Husky Oil Operations Limited (Whiterose)
1045	Husky Oil Operations Limited (Whiterose)
1046	Husky Oil Operations Limited (Hebron I-13)
1049	Statoil Canada Ltd.(King's Cove A-26)

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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
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