Petroleum Resource Development

Activity Report 2010

Newfoundland Labrador

it's happening here.

Department of Natural Resources
Petroleum Resource Development
Activity Report - 2010

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1.0 Introduction

Newfoundland and Labrador, Canada's most easterly province, has been an active oil producing region for the past 13 years. The province's four oil projects; Hibernia, Terra Nova, White Rose and North Amethyst produced in excess of 100 million barrels of oil in 2010. This level of production accounted for approximately one third of Canada's conventional light crude output. Exploration and development continued both offshore and onshore in 2010 and this report highlights the petroleum development activity within the province's many sedimentary basins.

The graph below shows that world oil prices have ranged from the mid $60 to almost $90 per barrel in 2010. The value of the province's oil production was in excess of $8.0 billion CAD in 2010 and was a significant contributor (approximately 30%) to the province's gross domestic product (GDP). Further, the industry accounts for almost 2.5% of provincial employment.

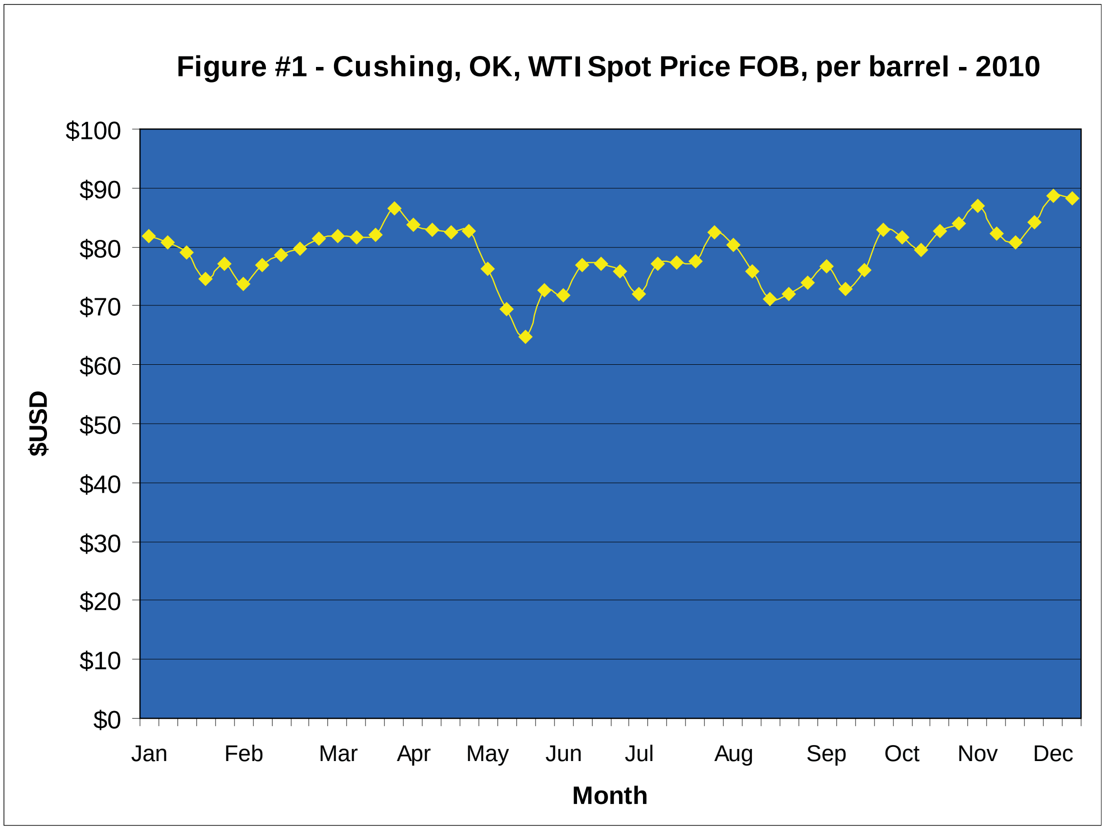
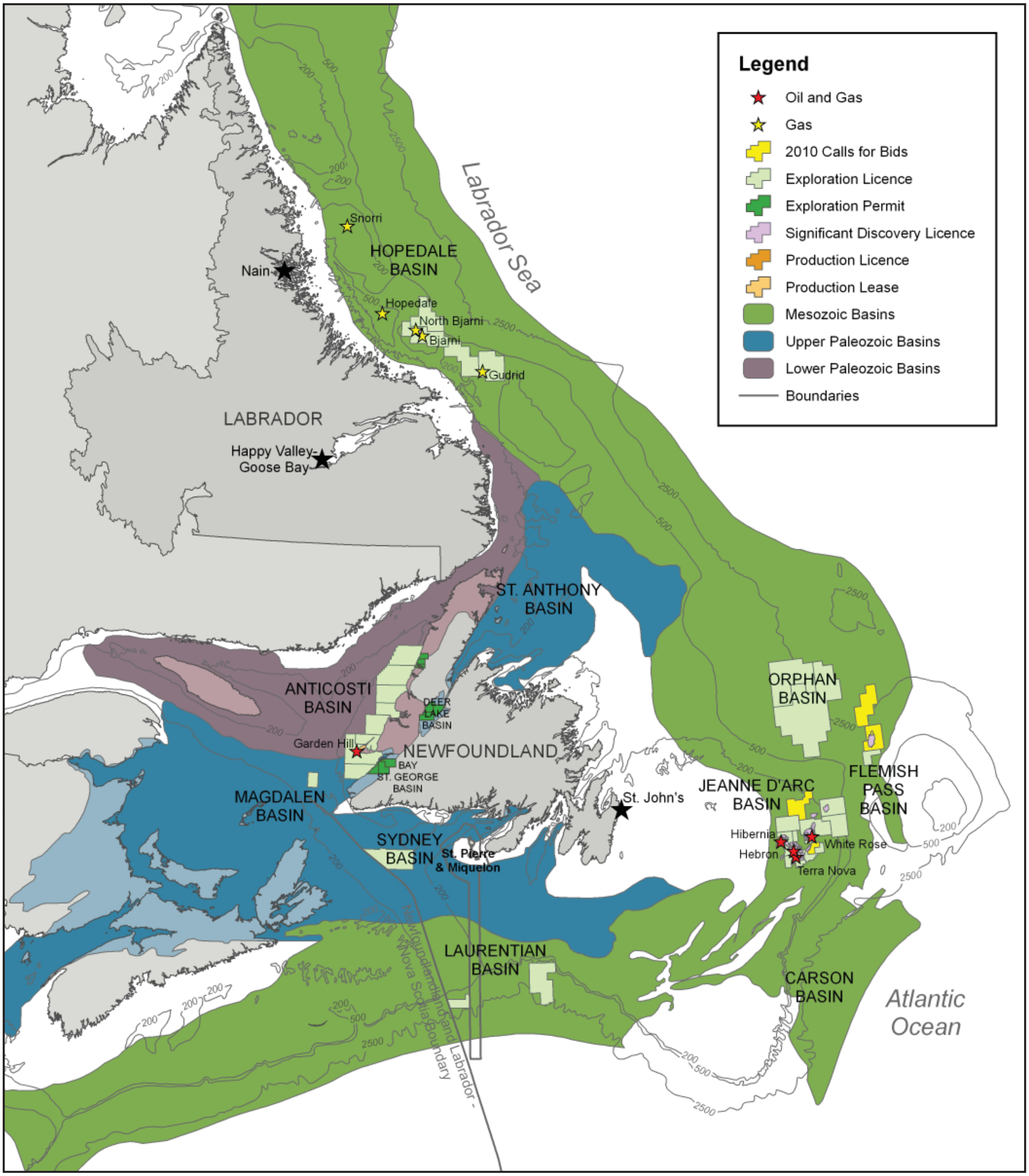


Figure #2 - Sedimentary Basins of Newfoundland and Labrador



As of December 31, 2010 Newfoundland and Labrador had discovered reserves of 3.1 billion barrels of oil and 11 trillion cubic feet of natural gas. Geoscience data indicates that a further 6 billion barrels of oil and 60 trillion cubic feet of natural gas remain undiscovered. Cumulative oil production totalled 1.2 billion barrels of oil as of December 31, 2010.

The province's newest producing field, North Amethyst, produced first oil on May 31, 2010. This marked another milestone for the province as it represented production from Canada's first offshore satellite tieback project. Development activity proceeded within existing fields in 2010 including the southern portion of the Hibernia field as well as the western portion of the White Rose field.

Work also continued in 2010 to advance the Hebron development. It is expected to be the province's fifth producing field and it is forecasted to commence production in 2017. Major contracts have been awarded by the operator for front end engineering and design on the topsides portion and also for the gravity based structure.

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, 2010 the C-NLOPB had 33 exploration licenses, 49 significant discovery licenses and 8 production licenses on record. During 2010 successful work expenditure bids totaling $111,494,000 were received on Calls for Bids conducted in the Jeanne d'Arc and Flemish Pass basins. Exploration licenses will

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						
Hibernia	221.9	*1395*	55.9	*1984*	35.8	*225*
Terra Nova	66.6	*419*	1.5	*53*	0.6	*4*
Hebron	92.4	*581*	-	-	-	-
Whiterose	48.4	*305*	85.3	*3023*	15.3	*96*
Ben Nevis	18.1	*114*	12.1	*429*	4.7	*30*
West Bonne Bay	5.7	*36*	-	-	-	-
North Amethyst	10.8	*68*	8.9	*315*		
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	**485.9**	*3056*	**191.9**	*6804*	**60.3**	*379*
Labrador Shelf						
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	**0.0**	*0*	**119.6**	*4244*	**19.9**	*123*
Total	**485.9**	*3056*	**311.5**	*11048*	**80.2**	*502*
Produced[4]	189.3	*1191*	0.0	*0*	0.0	*0*
Remaining	**296.6**	*1866*	**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 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. Gas, NGLs[3], and oil in undeveloped fields are currently classified as resources.
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 Produced volumes as of December 31, 2010. Produced oil reserves also include a small quantity of natural gas liquids.
* NGL estimates have not been updated since 2006.

be issued on these land parcels early in 2011 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. Note that there were no changes in the number of permits or leases in 2010. As of December 31, 2010 the province had 9 exploration permits and one production lease on record. The exploration licenses onshore, encompassing approximately 288,500 hectares, are 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.

The high level of exploration drilling onshore western Newfoundland continued in 2010. Following two exploration wells completed by Vulcan Minerals in 2009, Nalcor Energy completed two exploration wells and Deer Lake Oil and Gas drilled one exploration well on their various licenses. Several of the wells encountered gas bearing zones and further analysis and completion programs are expected to be conducted in 2011.

In 2010 the Province of Newfoundland and Labrador completed a Call for Posting, which is the preliminary step in announcing a Request for Bids for an onshore land licensing round. Approximately 28,000 square kilometres of land was open for nomination and the Call for Postings closed on December 15, 2010.

The local partners in the rig sharing agreement for the semi-submersible drilling rig, Henry Goodrich, reached an agreement in 2010 to extend the contract for the rig for an additional 3 year period. As mentioned previously, the 2010 offshore Calls for Bids generated an additional $111,494,000 CAD in new offshore work expenditure commitments. This raised the total outstanding offshore work expenditure commitment to close to $1 billion CAD at the end of 2010 which bodes well for future exploration and development.

Three major 2D seismic programs were conducted in the Newfoundland and Labrador region in 2010. Husky Energy completed a program offshore Labrador covering 5,550 line kilometers as well as a 3006 line kilometer offshore program in the Sydney basin. Lastly Vulcan Minerals completed a 130 line kilometer onshore 2D survey in Flat Bay. This survey is one of the largest onshore seismic surveys ever completed in Newfoundland.

As of December 31, 2010 a total of 362 wells have been spudded in Newfoundland and Labrador's offshore waters. A total of 49 significant discovery licenses have been issued by the C-NLOPB in 25 areas including 5 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 the size of the discovery. An estimate of the size is not expected to be released until the full extent of the Mizzen discovery is determined.

The tragedy and environmental damage with the Deepwater Horizon incident in the Gulf of Mexico in April, 2010 had an affect on petroleum exploration on a worldwide basis. Newfoundland and Labrador was not immune. Subsequent to the Macondo blowout, the C-NLOPB implemented extra oversight measures on exploration wells staring with the Chevron et al. Lona 0-55 well which was spud on May 10, 2010. The exploration well was drilled in the Orphan Basin in approximately 2600 metres without incident.

Offshore petroleum exploration activity is expected to be maintained at a high level in 2011. Suncor has announced that they will be returning to their Ballicatters prospect in Jeanne d'Arc Basin to drill a sidetrack exploration well. Further, Statoil have announced plans for a delineation well at their Mizzen prospect in the Flemish Pass Basin as well as an exploration well in the Jeanne d'Arc Basin at their Fiddlehead prospect. 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.

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.

Hibernia GBS

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, 1.864 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.

During 2010 two wells were completed bringing the total number of development wells being utilized at the main Hibernia field to 64. They include 35 oil producers, 23 water injectors and 6 gas injectors. Hibernia produced 56.3 million barrels of oil during 2010 giving an average daily production of 154,348 bopd. Cumulative oil production to December 31, 2010 was 722.9 million barrels representing 51.8% of the total current reserve estimate.

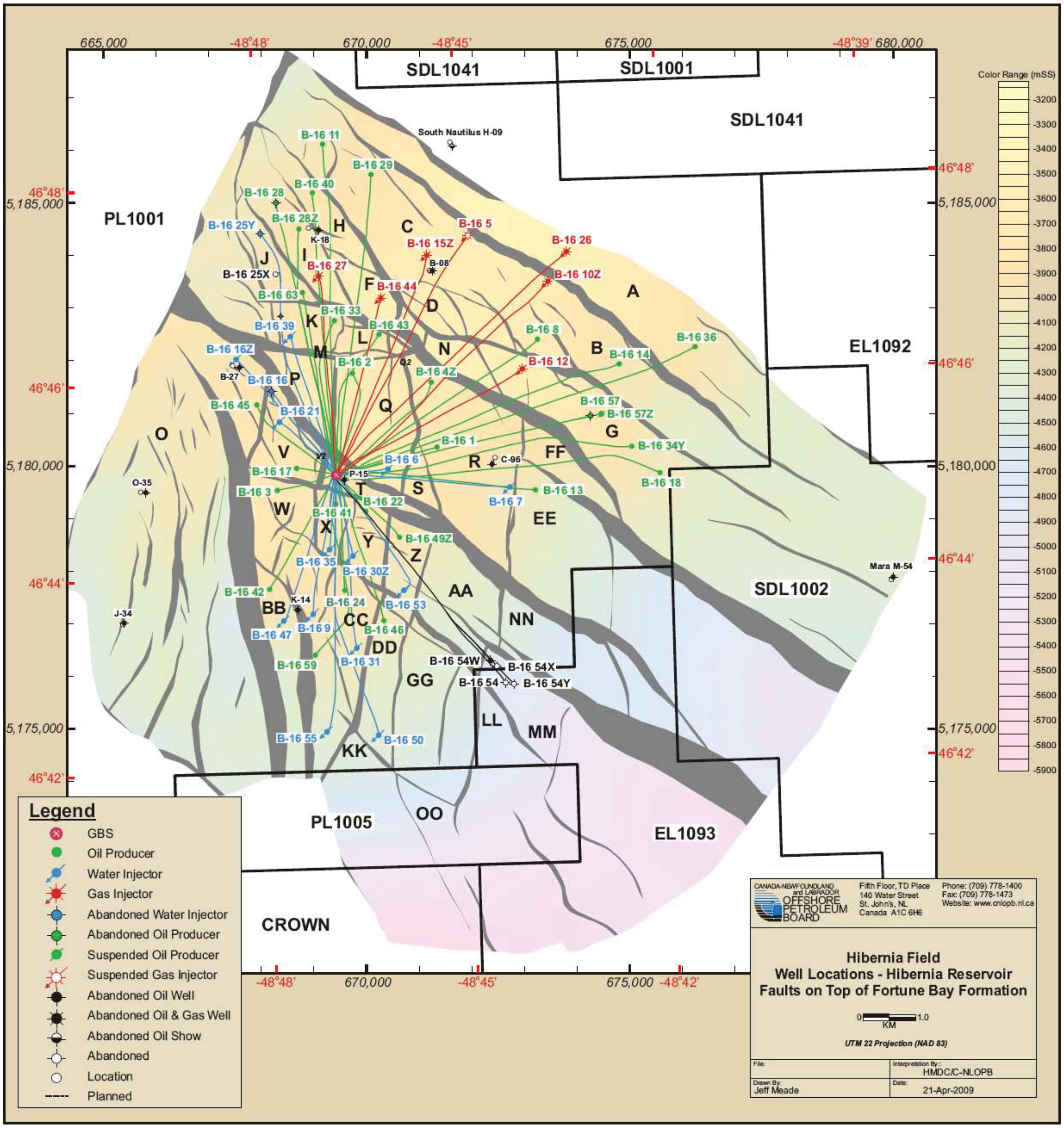
In concert with the production of oil, the Hibernia platform also produces and handles natural gas. Since gas injection began in 2000, approximately 90% of the gas produced has been re-injected into the reservoir for pressure maintenance and to optimize oil recovery. The balance of the gas that is produced is mainly used as the primary fuel source for the platform.

Oil production in 2010 was higher than originally expected and was the result of production commencing from Hibernia's AA Block as discussed in section 2.1.1 of this report. 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. Since that time the partners have been working on plans to develop this area and have divided the Hibernia Southern Extension 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 - Structure Map of Hibernia Reservoir



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 on August 18, 2009. The program for the AA Block included drilling four development 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).

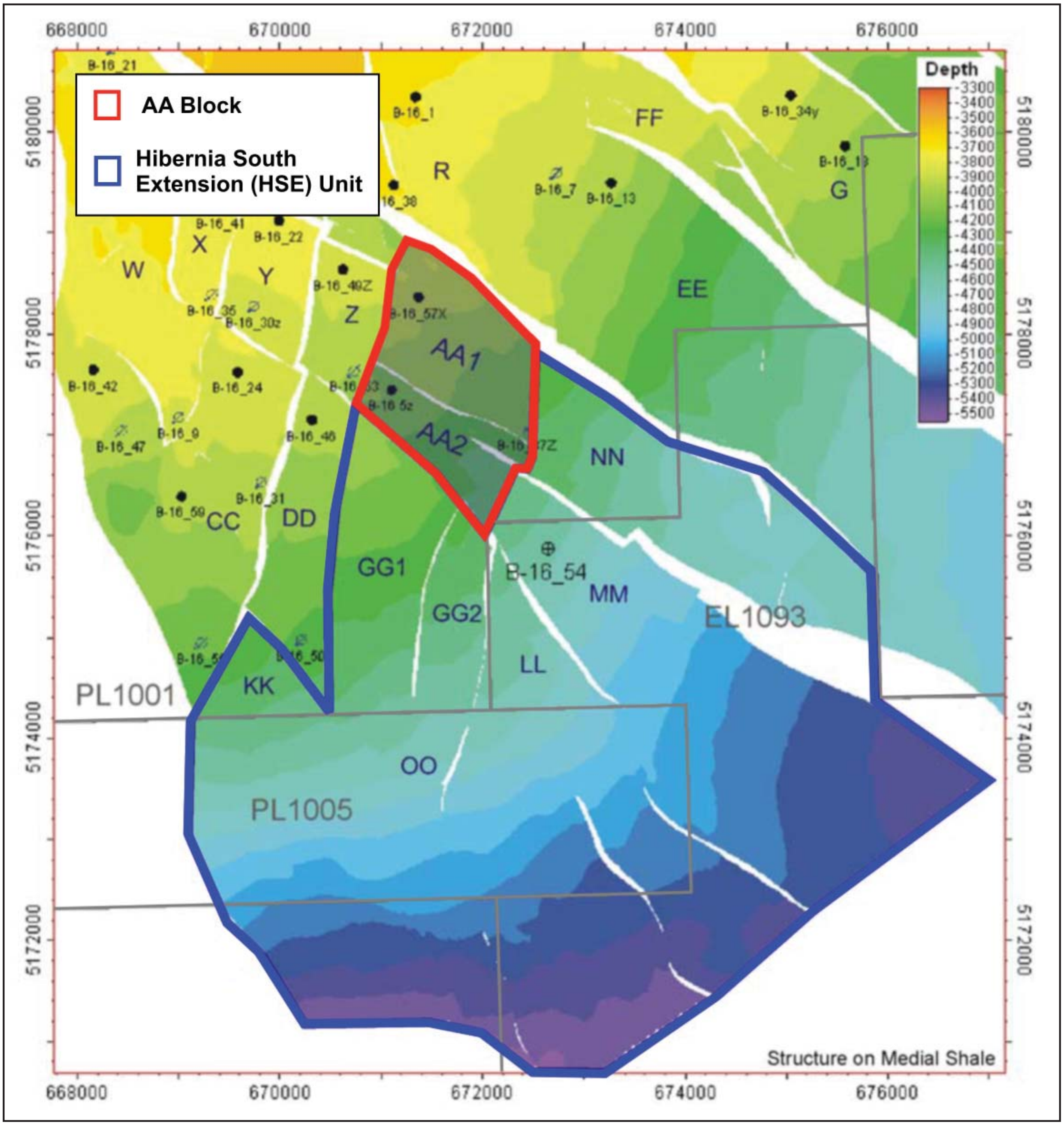
The C-NLOPB has assigned a recoverable reserve estimate of 48 million barrels of oil for the AA Block. Note that these reserves are included in the overall Hibernia recoverable reserve estimate of 1.395 billion barrels of oil mentioned previously in Section 2.1 - Hibernia - Main Field. Production from the AA Block is 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 is 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 2010, 8.1 million barrels of oil were produced from the AA Block giving an average daily production of 22,075 barrels of oil. The total cumulative production to December 31, 2010 was 8.3 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 has agreed to cover 10% of future development costs and in return will receive 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 show 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 resource estimate for the Hibernia field. Development of the HSE Unit will include a combination of wells drilled from the Hibernia platform as well as from a subsea drilling program utilizing a mobile offshore drilling unit. The total cost of the HSE development is estimated at $1.735 billion CAD with the subsea and platform drilling 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. Drilling of these wells is scheduled to commence early in 2013 and continue for approximately 2 years. This drilling schedule may commence earlier depending on drilling performance on the platform. The subsea drilling program is scheduled for 2013 to 2015 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.

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. Note that first oil from the HSE Unit is not expected until late in 2013.

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 the Exploration Licenses (EL-1093).

With respect to 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 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. This 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 oil commercial 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	33.99%
ExxonMobil	22%
Husky Oil	12.51%
Statoil ASA	15%
Murphy	12%
Mosbacher	3.50%
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 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.

Terra Nova FPSO

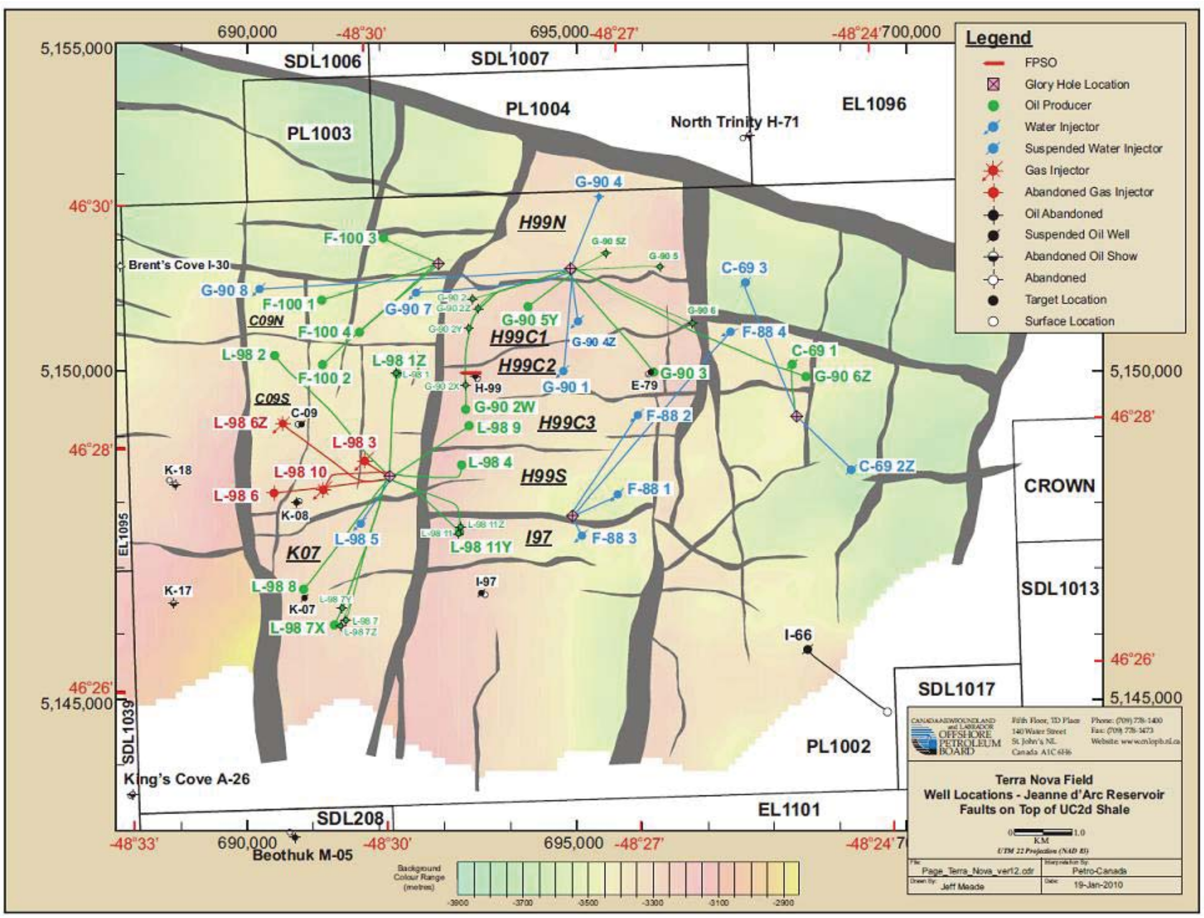
The latest recoverable reserve estimate for the Terra Nova field, released in 2009, includes 419 million barrels of oil, 53 billion cubic feet of natural gas and 4 million barrels of natural gas liquids. The approved production rate for the Terra Nova FPSO is 180,000 barrels of oil per day.

As of December 31, 2010 Terra Nova had a total of 27 development wells completed. This consisted of 15 oil producers, 9 water injectors and 3 gas injectors. During 2010 the field produced 24.9 million barrels of oil equating to a daily production of 68,325 bopd. Cumulative field production to the end of 2010 was 311.4 million barrels of oil which represents 74.3% of the recoverable reserve estimate.

Production was down in 2010 versus planned forecast as a result of the operator closing in some wells late in the year to address issues arising with the discovery of hydrogen sulphide (sour gas). Suncor have announced that they are investigating the sour gas issue and will be implementing corrective measures in upcoming maintenance programs.

During the 2010 maintenance operation at the Terra Nova field, Suncor Energy completed a major valve replacement program on gas injector wells being used. The program included using a team of 12 saturation divers on the sea floor to remove and replace annular choke valves. The water depth in the area is approximately 105 meters and it was the first time this type of maintenance work was conducted on the Grand Banks. The work was completed to improve performance and included the complete shutdown of the Terra Nova FPSO to ensure safe operations during the maintenance period.

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 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 contained in the main White Rose field (South Avalon

White Rose FPSO 'Sea Rose'

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 reserve 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.

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 with total cumulative production of 152.8 million barrels of oil as of December 31, 2010. In 2010 production at the White Rose field totalled 15.7 million barrels of oil which equated to an average daily production of 45,925 barrels of oil per day. The field is being developed utilizing 21 development wells consisting of 8 production, 10 water injectors and 3 gas injectors.

Figure #6 - White Rose Development Area

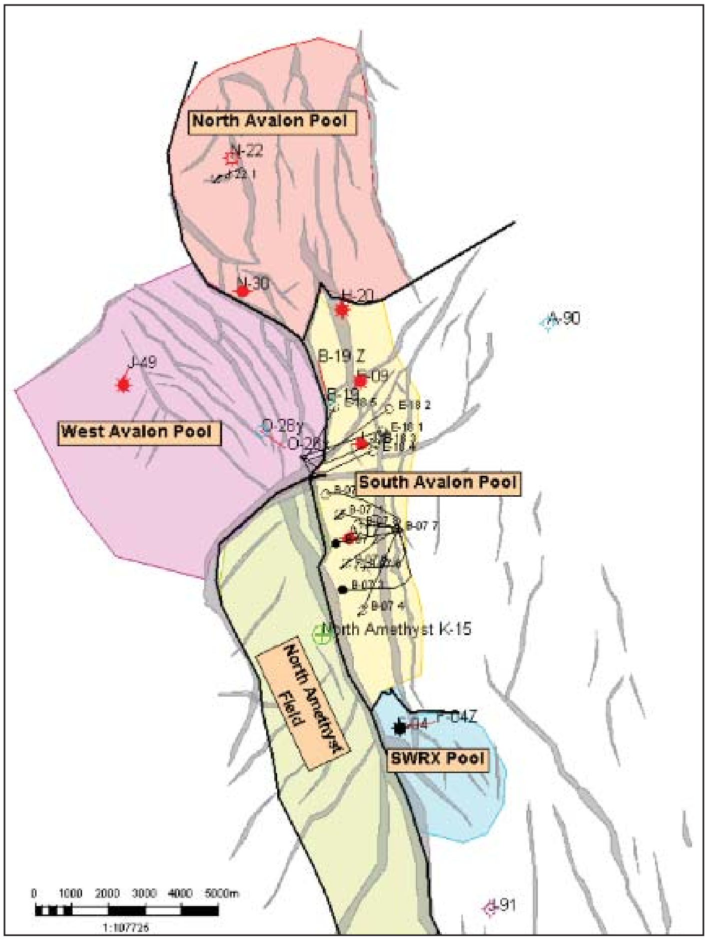
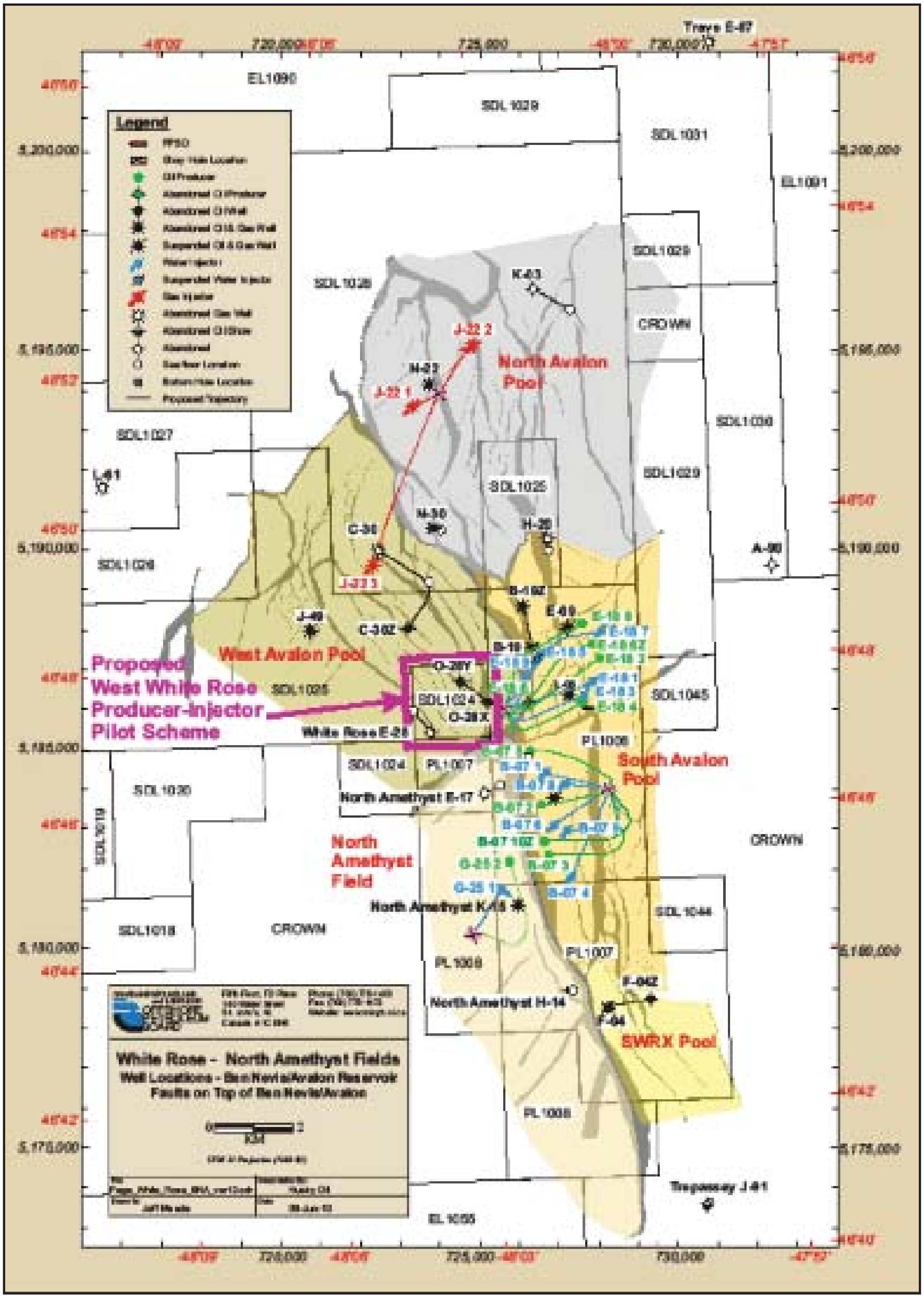


Figure #7 - White Rose Development Area



2.3.1 West White Rose

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 (SDL) 1047. Deliniation drilling in the region included the drilling of the J-49, O-28Y, O-28X, C-30, C-30Z, E-28 and J-22 3 wells. However, even with this level of drilling the co-venturers believe there is still uncertainty with the geological modelling of the area.

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 is scheduled to begin producing in 2011. The second well if it is deemed necessary will be a water injector and is scheduled for completed in 2011. The initial estimated cost for the West White Rose pilot scheme was $250 million CAD which includes 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 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 estimate for White Rose as detailed in Section 2.3.

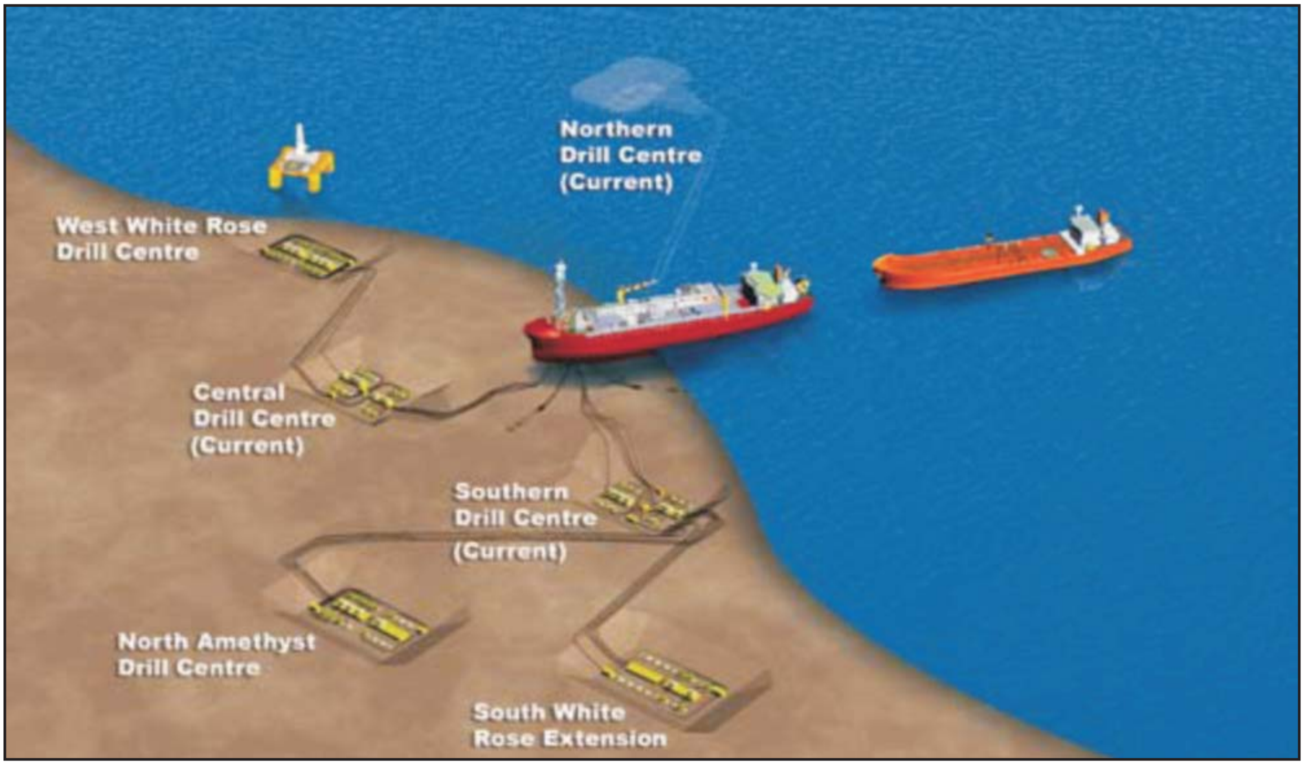
2.4 North Amethyst Field

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, 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 new 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 is 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 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

Figure #8 - North Amethyst Tie Back Development via White Rose FPSO

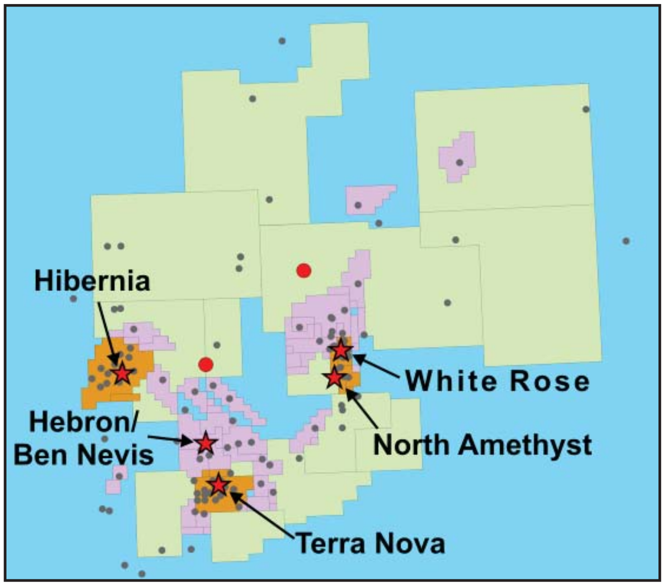


resources were discovered at North Amethyst (Hibernia Formation), totalling approximately 60 million barrels of original oil in place. Further details on these new resources have not been released and the C-NLOPB have not yet completed an analysis of the new discovery for reserve estimates.

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 on May 31, 2010 was accomplished using two producers (G-25 2 and G-25 3) and one water injector (G-25 1). A second water injector (G-25 4) was completed in 2010. Cumulative production to December 31, 2010 was 3.8 million barrels of oil for an average daily production of 10,267 barrels.

Production from North Amethyst was an important milestone as it represents 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.

Figure #9 - Jeanne d'Arc Basin



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 #9 on page 21 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 include an additional 150 million barrels of oil, 429 billion cubic feet of natural gas and 30 million barrels of natural gas liquids.

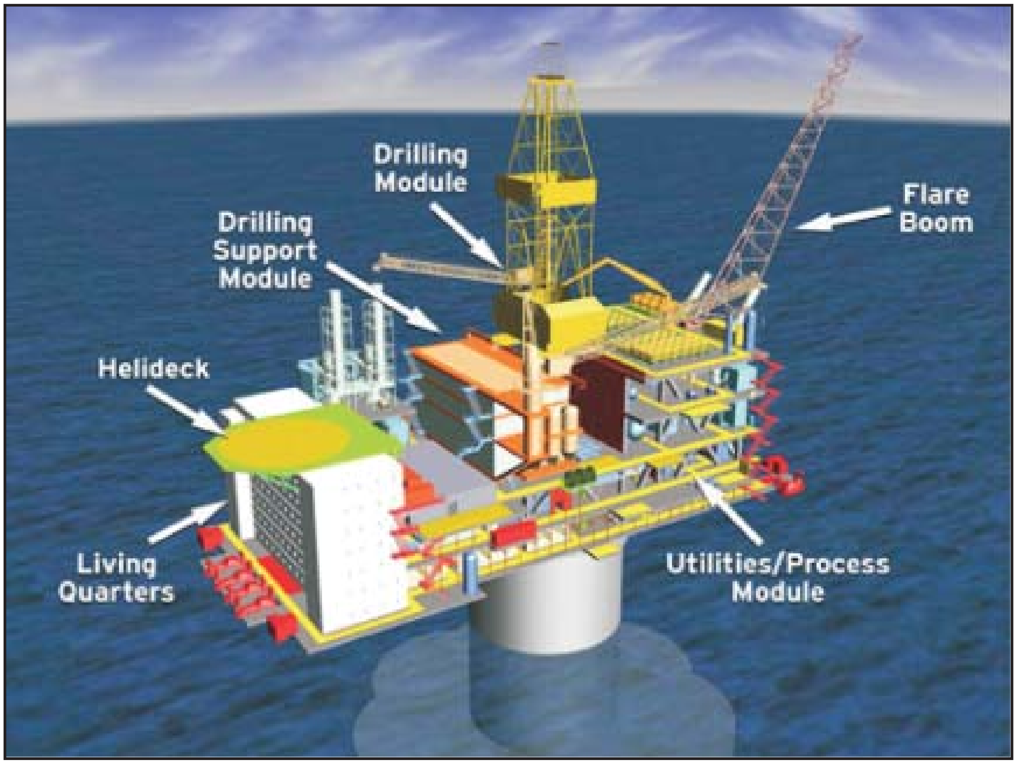
Formal agreements were signed with the co-venture partners and the Government of Newfoundland and Labrador to develop the Hebron offshore development on August 20, 2008. As part of the agreement Nalcor Energy - Oil and Gas purchased a 4.9% stake in the project at a cost of $110 million CAD. It was also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

Initial development in the Hebron project area will consist of producing oil reserves from the Hebron field only 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. Construction costs of the Hebron GBS and topside facilities have been estimated at $4 - $6 billion CAD.

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.

Also on November 9, 2010 ExxonMobil announced the awarding of the GBS FEED contract to Kiewit-Aker Contractors. Kiewit-Aker Contractors is 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 Marystown Shipyard and the Cow Head fabrication yard located in the province. 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. Construction of the GBS is expected to commence in 2012 at the Bull Arm site with first oil expected in 2017.

Figure #10 - Propose Hebron GBS



2.6 Garden Hill South

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

Figure #11 - Location of Port au Port Peninsula

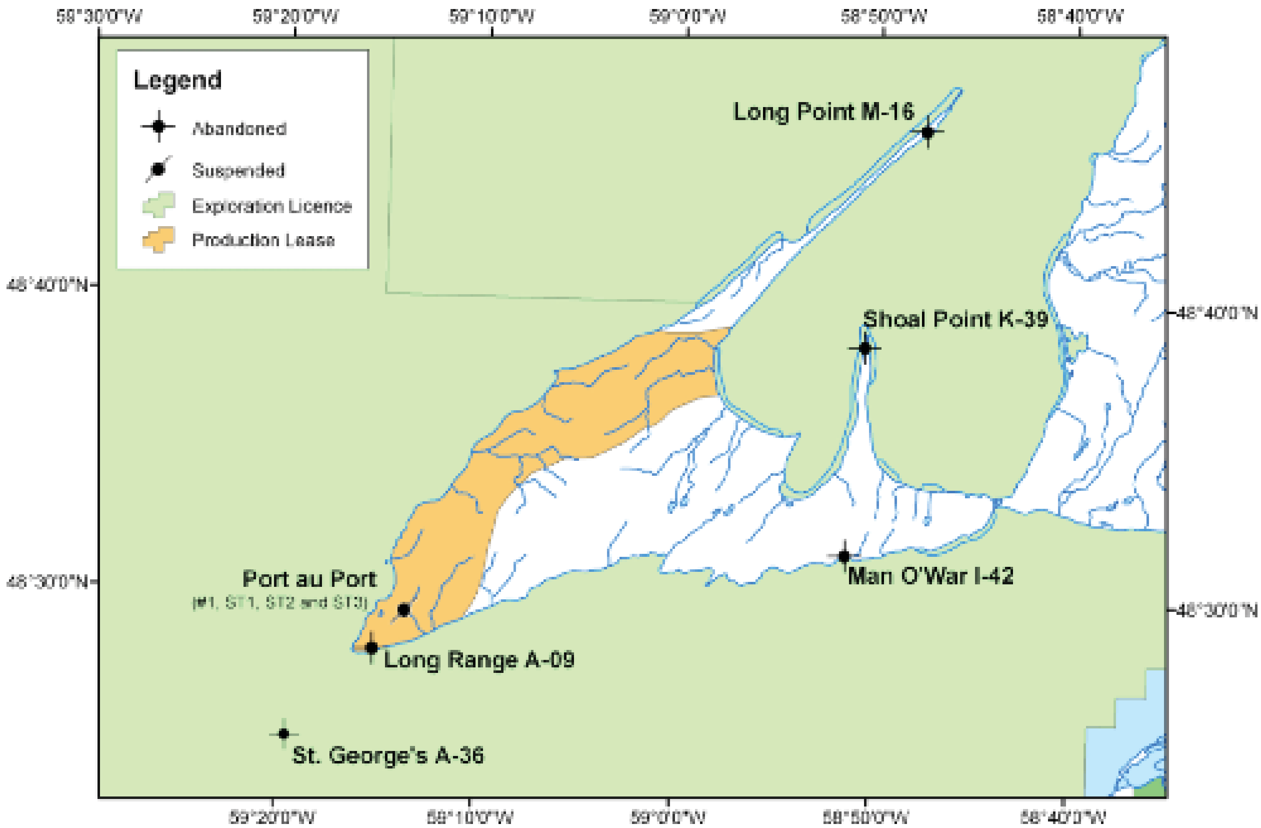
Activity at the Garden Hill site commenced in September, 1994 when Hunt/Pan Canadian drilled the Port au Port (PAP) #1 well. The well encountered two hydrocarbon bearing intervals within Aguathuna Formation dolostones with flow rates of 1,528 and 1,742 barrels of 51 degree API oil and 2.6 and 2.3 million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

Several sidetrack wells have been drilled at PAP #1 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. In December, 2009 PDIP entered into a farm-out arrangement with Dragan Lance Management (DLMC) whereby DLMC would pay 100% of the cost to further develop and operate PAP #1 side-track #3. In return DLMC would earn a 40% working interest in this well at the Garden Hill Site.

In 2010 DLMC commenced several workover programs on the well in an attempt to improve the connectivity between the well bore and the reservoir. As a result of the workover and testing programs being conducted oil production in 2010 was reduced from previous levels. Garden Hill South produced approximately 1300 barrels of oil in 2010 bringing the total production at the site to just over 35,000 barrels of oil. Further workover and testing programs are planned in 2011 to improve productivity. It is hoped that these programs will sustain long term production in the range of 200 barrels of oil per day.

The lease at Garden Hill contains the discovered field at Garden Hill South as well as two other leads at Garden Hill Central and Garden Hill North. The farm out agreement with DLMC includes options for them to acquire interest in these prospects based on completion of exploration and development programs.

Figure #12 - Port au Port Peninsula



3.0 Regional Activity Update

3.1 East Coast Offshore - North Grand Banks

Resource Opportunity - 2010 Call for Bids

There were three licensing rounds completed in 2010 for land parcels in Jeanne d'Arc Basin and the Flemish Pass/Central Ridge area as detailed in Figure 13 on page 27.

Exploration licenses for Call for Bids NL10-01 and NL10-02 will be issued early in 2011 when the terms and conditions of the licenses are met. The criteria used for evaluation of the bids was the highest total work expenditure commitment submitted. The amount of the successful bids totalled $ 111,494,000 CAD with the successful bidders detailed in charts below.

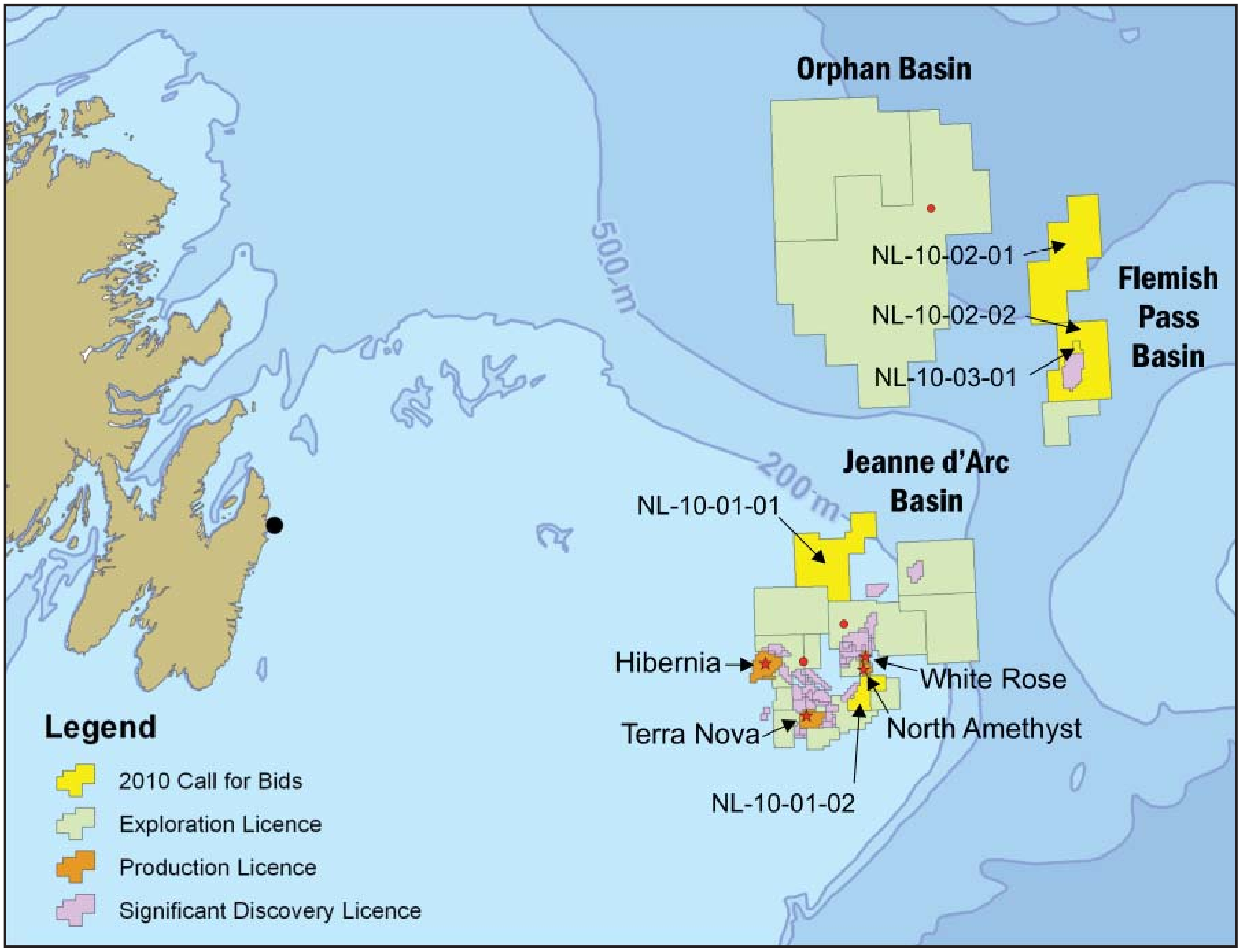
Call for Bids NL10-01 (Jeanne d'Arc Basin)	
Parcel 1 (139,617 ha)	Bid amount - $1,150,000
Husky Oil Operations Limited	67%
Repsol E&P Canada Ltd.	33%
Parcel 2 (29,783 ha)	Bid amount - $15,150,000
Husky Oil Operations Limited	50%
Statoil Canada Ltd.	50%

Call for Bids NL10-02 (Flemish Pass/Central Ridge)	
Parcel 1 (201,951 ha)	Bid amount - $75,147,000
Statoil Canada Ltd.	75%
Repsol E&P Canada Ltd.	25%
Parcel 2 (125,421 ha)	Bid amount - $20,047,000
Statoil Canada Ltd.	65%
Husky Oil Operations Limited	35%

Call for Bids NL10-03 was issued for a Significant Discovery License (SDL) on the land parcel in the Flemish Pass Basin. Statoil and Husky were the successful bidder with a bid of $1,237,000 CAD. The SDL will also be issued in early January, 2011 when all terms and conditions are met.

Call for Bids NL10-03 (Flemish Pass/Central Ridge)	
Parcel 1 (3,773 ha)	Bid amount - $1,237,000
Statoil Canada Ltd.	65%
Husky Oil Operations Limited	35%

Figure #13 - East Coast Regional Map



Exploration Activity - Drilling Programs

A total of three exploration wells were spud in the East Coast Offshore region in 2010. On January 25, 2010 the drilling rig, Henry Goodrich spud the Glenwood H-69 exploration well on Exploration License (EL) 1090R for Husky Oil. The well was drilled in water depths of approximately 130 meters to a total depth of 3668 meters. The well was completed on March 19, 2010 and as the well was classified as a “tight hole”, no drilling results have yet been released.

The Henry Goodrich was also used to spud an exploration well on November 24, 2010 for Suncor Energy on land that straddles Exploration Licenses 1092 and 1113. The well (Ballicatters M-96Z) was a sidetrack follow-up to a previous exploration (M-96) drilled by Suncor in 2009. The well was drilled to a total depth of 4212 meters in water depths of approximately 100 meters. Suncor have not released detailed results but have announced that hydrocarbons were discovered. Further analysis of the drilling results are ongoing.

Chevron Canada, utilizing the drill ship Stena Carron, spud an exploration well (Lona O-55) in the Orphan Basin on EL 1074R. The well was spud on May 10, 2010 and completed on August 22, 2010. The well was drilled in water depths of 2600 meters to a total depth of 5580 meters. While no other deep water wells were being drilled in North America at this time, this well was drilled incident free. Once again, as the well was classified as a “tight hole” no information has been released on drilling results.

Geoscience Programs

Four wellsite surveys were completed by the MV Anticosti off the East Coast in 2010. ExxonMobil conducted surveys in the Jeanne d’Arc Basin at their Hebron and Hibernia South fields. Statoil also completed surveys around their licenses in the Jeanne d’Arc Basin (EL-1101) and also in the Flemish Pass Basin (SDL-1047).

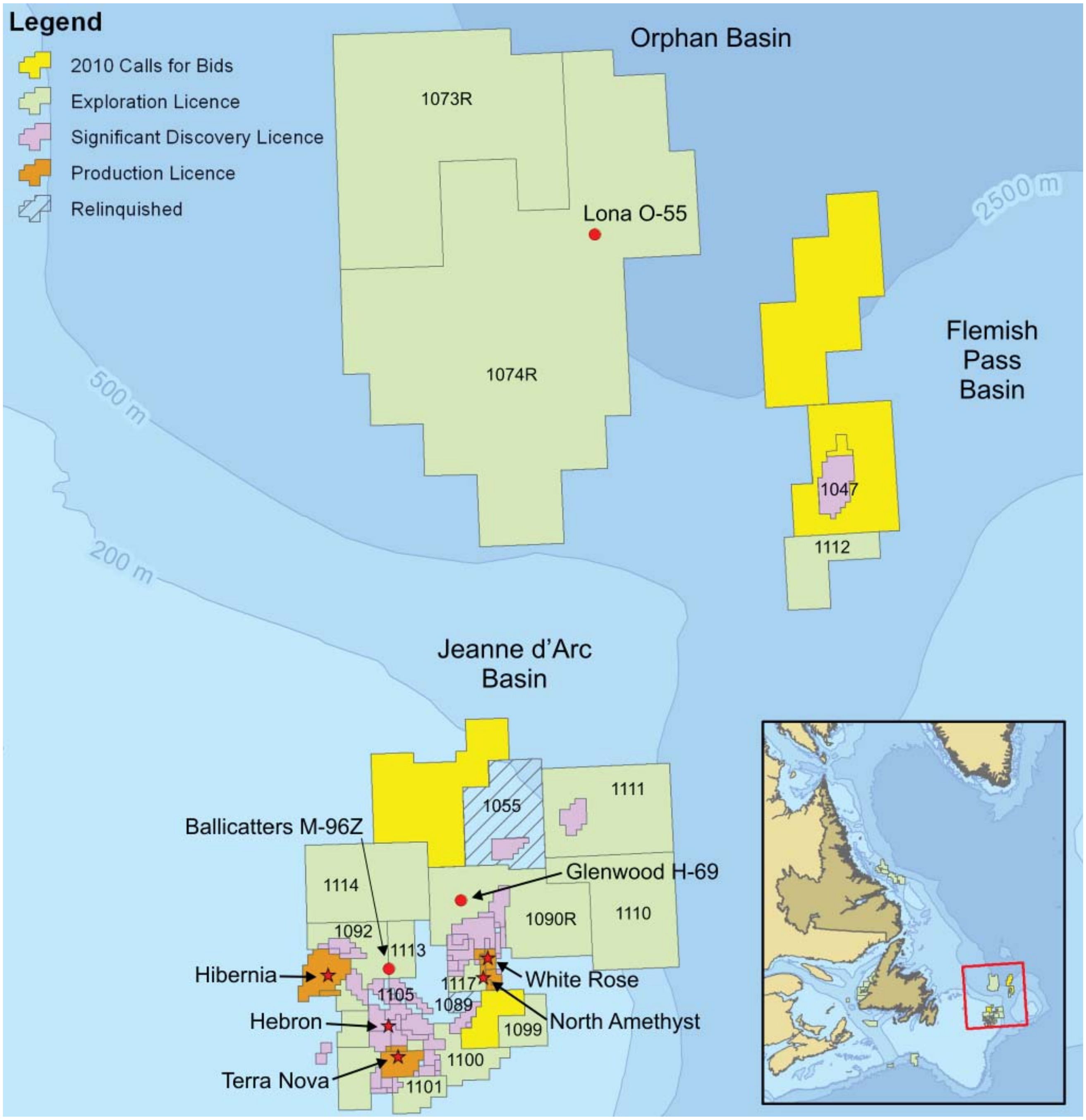
Licensing – Land Rights

One new exploration license (EL-1117) was issued by the C-NLOPB in January, 2010 for a land parcel in the Jeanne d’Arc Basin. The EL was issued to the co-venture partners Husky Oil (72.5%) and Suncor Energy (27.5%) as a result of their successful bid on the parcel in the 2009 Call for Bids (NL 09-01).

One consolidation was approved in 2010 for Husky Oil Operations Limited with Exploration

Licenses 1090 and 1091 consolidated into 1090R. Exploration Licenses 1089 and 1055 represented by Husky Oil Operations were at the end of their respective terms and the land was returned to crown reserve. Lastly the C-NLOPB issued a Significant Discovery License (SDL-1047) to Statoil for their Mizzen discovery on Exploration License 1049 in the Flemish Pass Basin.

Figure #14 - East Coast Regional Map - Well Locations



3.2 South Coast Offshore

Exploration Activity - Drilling Activity

Co-venture partners, ConocoPhillips Canada and BHP Billiton Petroleum, completed an exploration well (East Wolverine G-37) in the Laurentian Basin utilizing the modern drill ship Stena Carron. Located in 1890 meters of water, the well was spudded on November 24, 2009 and completed on April 23, 2010 to a total depth of 6,857 meters. The well is classified as a “tight hole” and detailed well evaluation results have not been released.

Geoscience Programs

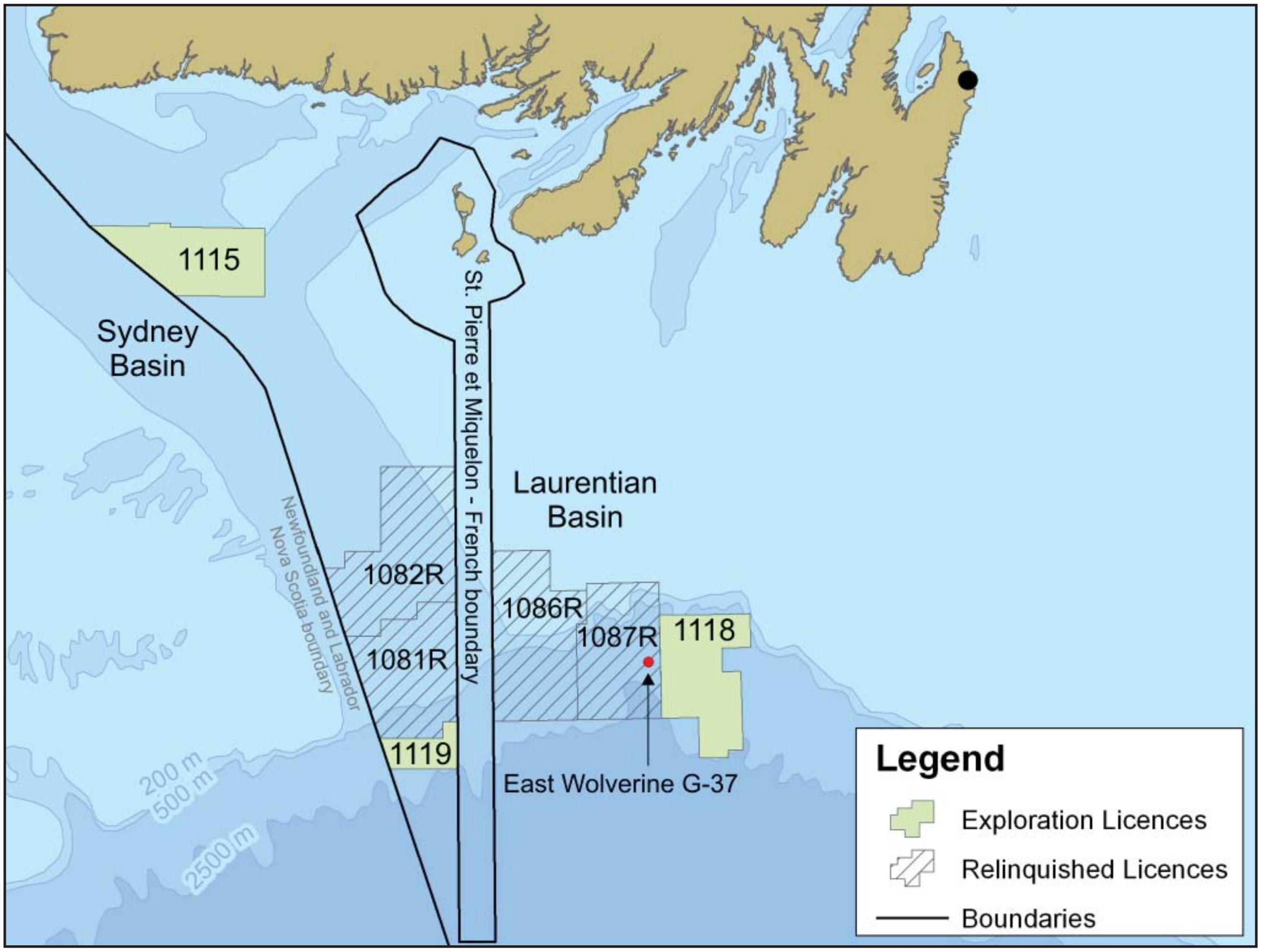
On June 22, 2010 Husky Energy completed an extensive 2D seismic survey on offshore land it acquired in the 2008 Call for Bids in the Sydney Basin. The survey, completed by Petroleum Geoscience Services (PGS) utilizing the MV Harrier Explorer collected 3006 line kilometers of data in the area of EL-1115.

Licensing - Land Rights

In January, 2010 two new exploration licenses (EL 1118 and 1119) were issued by the C-NLOPB in the Laurentian Basin stemming from the completion of the requirements of the 2009 Call for Bids. ConocoPhillips Canada and BHP Billiton Petroleum were the successful bidders on two parcels as shown in Figure 14 on page 31. The total amount of the successful work commitment bids was slightly in excess of $9.0 million CAD.

ConocoPhillips and BHP Billiton also relinquished rights to the four adjacent parcels. The co-venture partners chose not to exercise their rights to extend the licenses and the exploration rights reverted back to the crown. Figure 14 shows the land holdings before and after the lands were relinquished.

Figure #15 - South Coast Regional Map



3.3 West Coast Onshore and Offshore

Exploration Activity – Onshore Drilling and Completion Programs

Parsons Pond

Nalcor Energy – Oil and Gas, the Province's provincially owned energy company is the major interest holder (67%) in three Exploration Permits (EPs) 03-101, 03-102 and 03-103 in the Parson's Pond area. They commenced drilling the Seamus #1 exploration well, using Stoneham's Rig #11 on January 15, 2010, and it was scheduled to be the first of a three well $20 million exploration program. The well was completed on May 15, 2010 and was drilled to a depth of 3160 meters.

The second well, Finnegan #1, was spudded on September 9, 2010 also utilizing the Stoneham Rig #11. It was drilled to a total depth of 3130 meters and the rig was released on December 5, 2010.

Darcy #1, the third planned well is scheduled to commence early in 2011 once a road is constructed and the site work completed.

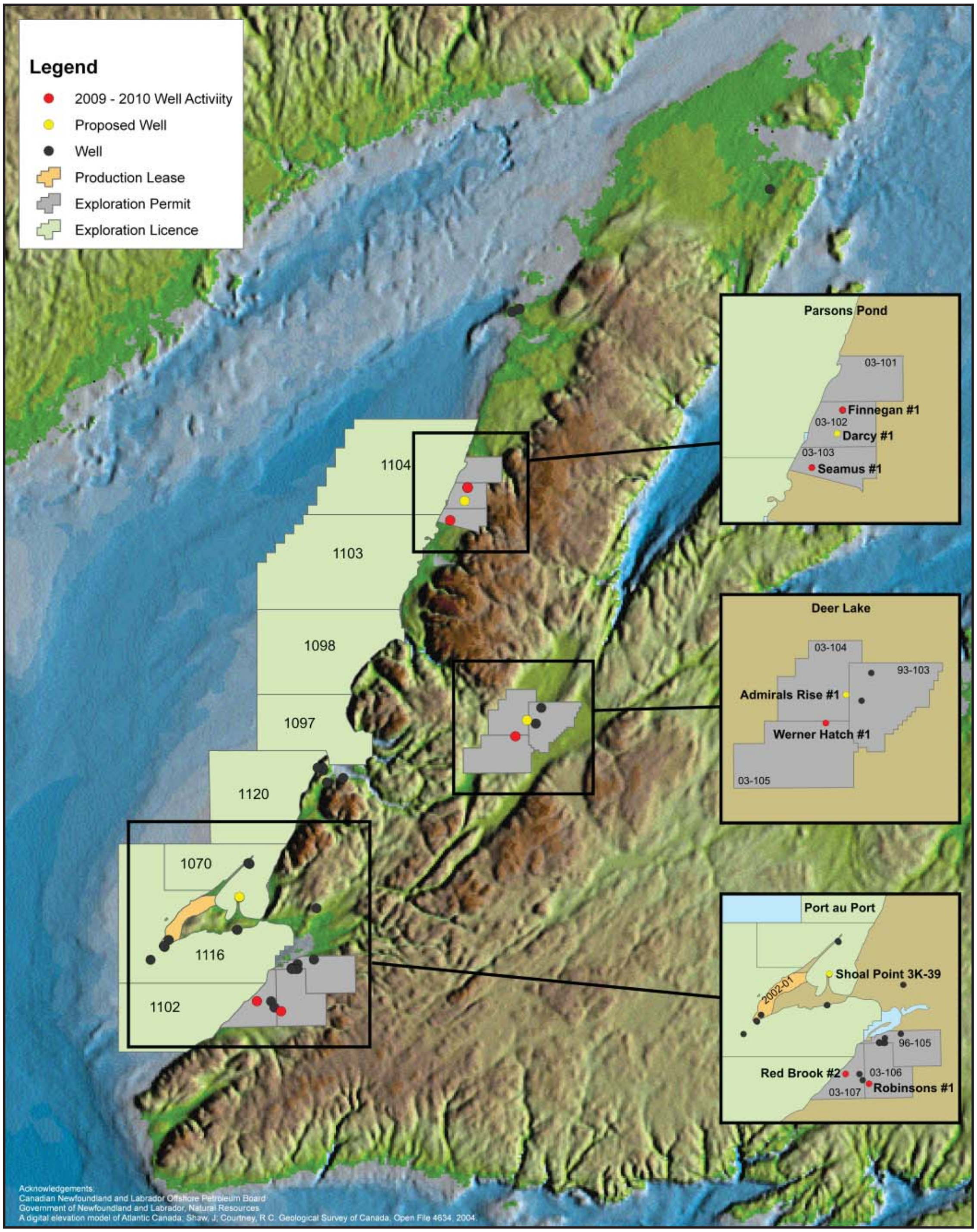
Nalcor has announced that both the Seamus #1 and Finnegan #1 wells encountered natural gas during drilling. A service rig, ECan Energy Rig #3, was located to Seamus site late in December, 2010 to commence well completion operations to help quantify the volume of gas discovered. Once testing is completed on the Seamus well it is expected that the rig will then move to the Finnegan site for similar work.

Bay St. George Area

Vulcan Minerals, owner's of EPs 96-105, 03-106 and 03-107, commenced completion operations on both the Robinsons #1 and Red Brook #2 wells in 2010 utilizing the ECan Energy Rig #3. The work included perforation of specific intervals in each of the wells for pressure and injectivity testing. The company plans to carry out a stimulation program to adequately test the flow rates of the prioritized zones in the first half of 2011.

The completions programs are the culmination of a wildcat drilling program in the Bay St. George Basin of western Newfoundland. The results obtained will 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.

Figure #16 - West Coast Regional Map



Deer Lake Area

Deer Lake Oil and Gas Inc. holds exploration permits EPs 93-103, 03-104 and 03-105 in the Deer Lake Basin. It drilled a shallow exploration well, Werner Hatch #1, utilizing the Logan #44 continuous coring drilling rig. The well was spudded on February 11, 2010 and released on March 31, 2010 after drilling to a total depth of 442 meters. Permitting for the Admirals Rise #1 well, also planned for the area, was in process as at December 31, 2010.

Exploration Activity - Offshore

Late in 2010 Shoal Point Energy announced plans for a follow up well to test the Green Point Formation within their shallow rights on EL1070. Shoal Point Energy and Canadian Imperial Venture Corporation hold the shallow rights as per an interest swap agreement with PDI Production Inc. Also Shoal Point Energy announced that it has repurchased its farm-out agreement with McLaren Resources which was signed in 2009.

Geoscience Programs - Offshore

Fugro Jacques Geosurveys completed a geohazard survey for Corridor Resources on their offshore exploration license EL-1105 in the Magdalen Basin. The survey, conducted utiliz-ing the M/V Anticosti, was completed on October 15, 2010 and a total of 147.5 kilometres of data was acquired.

Geoscience Programs – Onshore

Vulcan Minerals completed one of the largest seismic programs ever onshore western New-foundland over EPs 96-105, 03-106 and 03-107 located in the Bay St. George area. The program conducted from August 18, 2010 to November 14, 2010 collected 130 kilometers of data. Vulcan also completed a geochemical survey in the area to assist with seismic and structural interpretation of the Bay St. George Basin.

Licensing – Land Rights

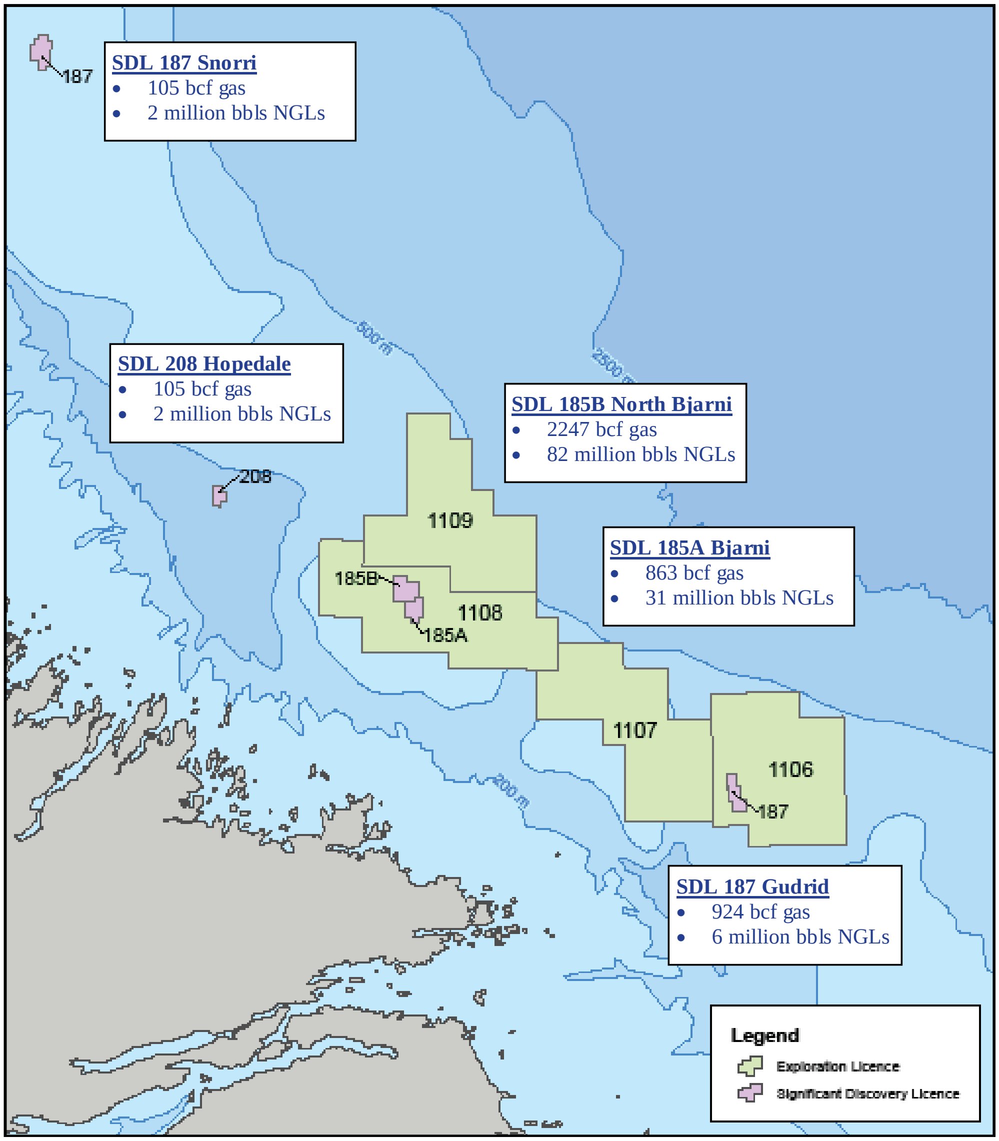
As a result of finalizing requirements on Call for Bids NL 09-03, exploration license EL-1120 was issued to Ptarmigan Energy Inc. on January 15, 2010. The land parcel covers an area of 140,210 hectares in the Anticosti Basin as shown in figure 15 on page 33.

3.4 Labrador Offshore

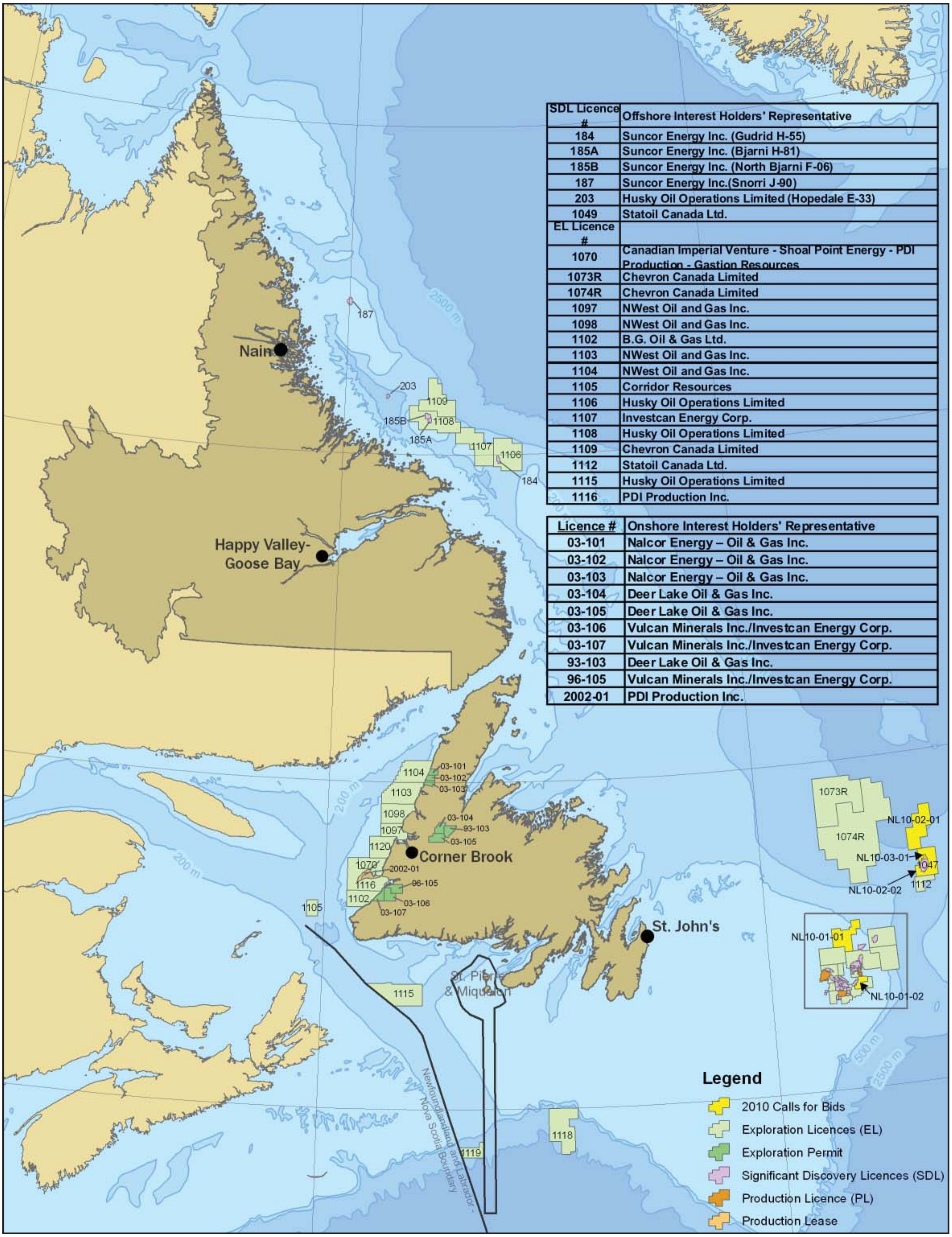
Geoscience Programs

PGS completed a major 2D seismic program in the Hopedale Basin offshore Labrador utilizing the M/V Harrier Explorer on behalf of Husky Energy. Husky Energy obtained approximately 2300 kilometers of data covering their ELs 1106 and 1108 and a further 3200 kilometers of data around EL-1107 held by Investcan Energy.

Figure #17 - Labrador Regional Map



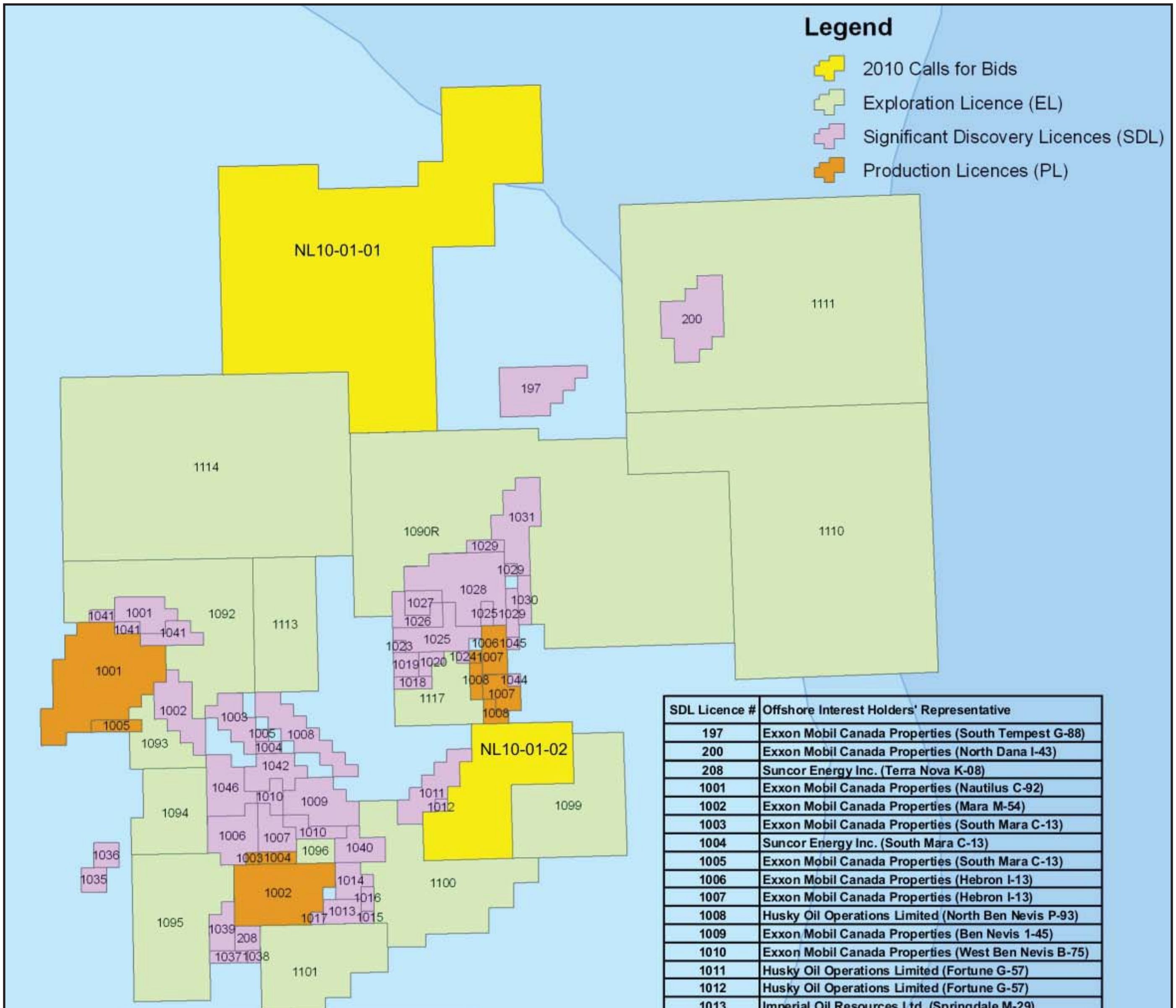
Appendix A



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)
1049	Statoil Canada Ltd.
EL Licence #	
1070	Canadian Imperial Venture - Shoal Point Energy - PDI Production - Gastion Resources
1073R	Chevron Canada Limited
1074R	Chevron Canada Limited
1097	NWest Oil and Gas Inc.
1098	NWest Oil and Gas Inc.
1102	B.G. Oil & Gas Ltd.
1103	NWest Oil and Gas Inc.
1104	NWest Oil and Gas Inc.
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.

Licence #	Onshore Interest Holders' Representative
03-101	Nalcor Energy – Oil & Gas Inc.
03-102	Nalcor Energy – Oil & Gas Inc.
03-103	Nalcor Energy – Oil & Gas Inc.
03-104	Deer Lake 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.

Appendix B



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)

EL Licence #	Interest Holders' Representative
1092	Suncor Energy Inc.
1093	ExxonMobil Canada Properties
1094	Husky Oil Operations Limited
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

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)

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Newfoundland Labrador

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