Petroleum Potential and Exploration Framework of Western Newfoundland Sedimentary Basins





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1. INTRODUCTION TO NEWFOUNDLAND AND LABRADOR OIL AND GAS INDUSTRY

The Canadian province of Newfoundland and Labrador (NL) is the sole Atlantic offshore area north of Florida containing giant producing oil fields. Approximately 1,000,000 km² of Mesozoic and Paleozoic basins with oil and gas potential are distributed in and around the province of Newfoundland and Labrador, an area larger than the Gulf of Mexico or the North Sea. Oil is the major contributor to Newfoundland and Labrador's gross domestic product on an industry basis and accounts for a substantial portion of government revenues.

Newfoundland and Labrador is home to some of the largest prospective and least explored sedimentary basins in the world. However, only approximately 6% of the offshore and less than 9% of the onshore acreage is currently held under licence by industry. Reporting to both the Federal and Provincial Ministers of Natural Resources through Atlantic Accord Acts, the offshore exploration activity is regulated by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). All onshore petroleum activity falls under authority of the provincial Department of Natural Resources, Energy Branch (DNR).

Newfoundland and Labrador's petroleum production comes from the Hibernia, Terra Nova, White Rose, North Amethyst fields and their satellites, located in the Jeanne d'Arc Basin. In each of the past five years, these fields have produced in the range of 200,000 to 300,000 barrels per day of light crude (30 to 35° API) from high quality Mesozoic sandstone reservoirs. Over 1.55 billion barrels have been produced to date from the NL offshore East Coast area. The recent increases in reserve estimates for the producing fields leave approximately 2.2 billion barrels of discovered resources to be produced. When taking into account the Ballicaters, new field discovery on the Grand Banks, more than 7.9 tcf of natural gas has been discovered on the Grand Banks, but there is currently no commercial gas production. The Jeanne d'Arc Basin developments are the only East Coast North America producing oilfields. The next offshore project Hebron, estimated to contain 707 mmbbls of recoverable reserves, is being developed by ExxonMobil and its partners, with first oil expected in 2017. Peak production for this field is estimated to be between 150,000 and 170,000 bopd.

The latest offshore Significant Discovery Licence (SDL) for an oil discovery through new drilling was awarded by the C-NLOPB to Statoil and Husky for the Mizzen O-16 well, which successfully tested 3,774 bopd of 21-22° API oil. In June 2013, Statoil announced a light oil discovery at the Harpoon O-85 well in the Flemish Pass Basin approximately 10 km southeast of the Mizzen find. This was immediately followed up with the announcement of another discovery at the Bay du Nord C-78 & C-78Z wells (August, 2013). Bay du Nord was announced as a 300-600 mmbbls recoverable light oil (34⁰ API) accumulation, while Harpoon's resources remain to be evaluated and disclosed.

Intense 2D and 3D seismic exploration is being conducted in various basins, much of which has not been previously imaged, but current wildcat drilling is focused mainly in the Flemish Pass Basin. Large modern 2D seismic grids have been acquired in these frontier basins commencing in the north in the Labrador Sea and encompassing the Orphan and Flemish Pass basins, all the way to the central and southern Grand Banks basins. There is a possibility that in future years, these 2D surveys will be expended to the offshore Maritimes and Anticosti basins.

Modern methods in seismic acquisition, processing and data interpretation implemented in the offshore program allow companies to identify subtle targets in the producing Jeanne d'Arc Basin and to make new discoveries in the less known, Mesozoic deeper water basins. Prospects and leads are large size structural or combination traps targeting high quality Late Jurassic and Early Cretaceous sandstone reservoirs sourced from the Late Jurassic world-class source rocks. While oil and gas have been tested in the Late Cretaceous and Early Cenozoic low stand sandstones in some exploration wells, these have yet to be proven as economic reservoirs.

In 2013, the C-NLOPB announced the implementation of a new scheduled land tenure system to provide longer lead times for exploratory work in frontier areas and improve transparency and predictability, as well as allowing for industry input into the process. Under the new system, the offshore area is divided into eight regions which are each designated as either low activity, high activity or mature depending on variances in the volume of data collection in the basins and geoscientific knowledge of the region. The Western Newfoundland and Labrador region is currently designated as a frontier low activity region however it has yet to be scheduled (Figure 1).

Numerous NL-DNR publications, brochures, website documents, maps and power point presentations discuss and illustrate the geological setting, petroleum exploration potential, exploration history of both eastern and western coasts of NL, the make-up of its oil and gas fields and undeveloped discoveries, and the components of the basins' petroleum systems (http://www.nr.gov.nl.ca/nr/publications/energy/index.html).

Despite a long exploration history and numerous hydrocarbon occurrences, the Western Newfoundland sedimentary basins remain underexplored. The hydrocarbon potential area totaling 18,000 km² (6,950 mi²) contains two Paleozoic basins, Anticosti and Maritimes, located both in the onshore and offshore. These basins are associated with the Appalachian foredeep and foldbelt chain of basins extending from West Texas to Labrador that contain numerous, conventional and unconventional oil and gas producing fields and discoveries.

The onshore part of Western Newfoundland has seen a great deal of historic and modern activity by intermediate and smaller oil and gas companies, some of local and international origin. The activity was focused on the Port au Port and Parsons Pond Lower Paleozoic areas of the Anticosti Basin, and the Bay St. George and Deer Lake Upper Paleozoic areas of the Maritimes Basin. Notwithstanding hundreds of oil shows, a proven light oil discovery on the Port au Port Peninsula, documented past production and numerous geological studies that point toward the existence of several working petroleum systems, these basins remain at a frontier stage of exploration. The basins have a limited number of modern exploration wells and poor to incomplete seismic coverage, but present exploration investment opportunities in both conventional and unconventional reservoirs.



Figure 1. Newfoundland and Labrador offshore land tenure regions (modified from C-NLOPB).

The main conventional petroleum plays are a) Lower Paleozoic hydrothermal (HTD) carbonates in both overthrust and platform settings, b) Lower Paleozoic porous sandstones in the synrift sequence or allochthon flysch, and c) Upper Paleozoic successor basin sandstones and carbonates. The Lower Paleozoic high organic marine shales on the Port au Port Peninsula represent the most important unconventional reservoir, but other lower quality reservoirs requiring stimulation techniques have been encountered in all areas.

A significant oil discovery was recorded in 1994 by Hunt/PanCanadian at Port au Port #1 well which tested 1,528 bopd and 1,742 bopd from two intervals within the oil-bearing upper Aguathuna Formation. The Ordovician reservoir comprises a low permeability matrix component and high permeability cavernous, paleokarst dolomites. Drilled on a small anticline, this discovery, delineated with sparse 2D seismic data is now understood to be a structural-stratigraphic (diagenetic) trap. The discovery is under a Production Lease (PL) known as the Garden Hill South field. Several past operators have intermittently produced small quantities of light oil from this field without reaching an economic development. Various industry estimates put the reserves between several million barrels to several tens of million barrels of recoverable resource (P50), but due to lack of modern 3D seismic coverage the boundaries of the field are difficult to map and these numbers are hard to confirm.

A high quality Ordovician source rock known as the Green Point shale was surface mapped and intersected by exploration wells in the Appalachian allochthon. Thick intervals of this organic rich, deep marine shale were logged in the Long Point M-16 well and Shoal Point K-39 well and its sidetracks, on the Port au Port Peninsula. Hundreds of metres of net pay have been encountered in all four wells. This shale has good to excellent reservoir qualities according to independent consulting studies and is similar to other Appalachian producing shale reservoirs such as the Utica of northeastern USA. The Green Point Formation extends from surface to depths of thousands of metres. There are instances when the Green Point Formation had poor quality source rock or wrong thermal maturity when drilled outside of the Port au Port Peninsula, however, this unit is regionally present and as an unconventional reservoir can host large volumes of hydrocarbons. At this time the play remains to be flow-tested using hydraulic fracture stimulation.

In 2013, the Province announced that it was not accepting applications for projects involving hydraulic fracture stimulation, commonly referred to as fracking, resulting in a pause in this activity. The provincial government also commissioned an independent external review of the method of fracturing underground rock to facilitate the extraction of oil and gas resources. The final report of the panel will be submitted to the Minister of Natural Resources when completed. For now the unconventional potential of the area discussed in this report remains tested by non-stimulation techniques of well logging and coring.

The geophysical data coverage in Western Newfoundland consists of 1270 line kilometres of 2D seismic reflection data and complete coverage with regional gravity and detailed aeromagnetic data. However, the seismic coverage is irregular and incomplete. No 3D surveys have been recorded onshore Newfoundland. The most recent drilling activity took place at Garden Hill and Shoal Point on the Port au Port Peninsula, in the Flat Bay anticline of the Bay St. George Basin and at Parsons Pond on the Northern Peninsula. Presently, activity is low, with no wells drilled in 2014

and no seismic acquisition planned for 2015. Five exploration permits (EPs) and one production lease (PL) are currently active but an onshore commercial petroleum development has yet to be realized in Western Newfoundland. Only three companies are active: Investcan Energy Corp. in the Bay St. George Basin, Black Spruce Energy in the Deer Lake Basin and offshore of the Port au Port Peninsula, and Enegi Oil Inc. at Garden Hill on the Port au Port Peninsula.

The Government of Newfoundland and Labrador through the Department of Natural Resources has initiated a series of scientific studies to gather new geoscience information and has also participated in updating the land tenure system in order to revive exploration in the area. As part of the provincial Energy Plan released in September 2007, policy actions were introduced to encourage and promote onshore and offshore exploration activity in the province. This translated into two funded programs: the Offshore Geoscience Data Program (OGDP) and the onshore Petroleum Exploration Enhancement Program (PEEP).

The OGDP received funding of \$20 million dollars and approved projects to date include potential field surveys for offshore western Newfoundland, a regional offshore satellite seeps survey and participation in a multi-client 2D seismic program targeting a vast expanse of the offshore, from northern Labrador to the southern Grand Banks.

The five million dollars allocated for PEEP saw a large percentage of funding directed towards source rock studies, regional mapping, aeromagnetic surveys and a petroleum geoscience data scoping study. The OGDP and PEEP initiatives are jointly administered by the Department of Natural Resources and Nalcor Energy. The Government of Newfoundland and Labrador encourages exploration in the sedimentary basins onshore Western Newfoundland and provides interested parties with all available information and data pertinent to these areas as provided for in the *Petroleum and Natural Gas Act* and subordinate regulations. This report was commissioned by the Department of Natural Resources in order to introduce interested companies to the petroleum potential and exploration framework of the Western Newfoundland sedimentary basins.

The report starts by describing the role of the Department of Natural Resources in onshore Western Newfoundland's oil and gas exploration and presenting the services they supply (Section 2) and continues with a detailed account of the history of onshore Western Newfoundland oil and gas exploration (Section 3). The core of the report presents the regional geoscience (Section 4) and petroleum geology and geophysics of Western Newfoundland's onshore sedimentary areas (Section 5). This is followed by a resource potential estimation (Section 6) and a description of prospective plays (Section 7). The report ends by providing the main conclusions (Section 8) and presenting a non-exhaustive reference list (Section 9). A table including the list of significant wells used in this report and a folio presenting the parameters of the most important plays in the four petroleum potential regions are also included.

The report is available from the Department of Natural Resources in both digital and printed report formats.

2. DEPARTMENT OF NATURAL RESOURCES/SERVICES SUPPLIED

2.1. Department of Natural Resources

The Department of Natural Resources (DNR) is responsible for regulating and encouraging the development of Newfoundland and Labrador's natural resources, namely minerals and energy (oil, gas, hydro, wind and biofuels); (<u>http://www.nr.gov.nl.ca/nr/</u>).

The Energy Branch of the DNR is responsible for the management of the oil and gas resources in the Province's onshore area (<u>http://www.nr.gov.nl.ca/nr/energy/index.html</u>). With respect to offshore petroleum activity, the department discharges its operational resource management functions under a joint federal-provincial regime administered by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) (<u>http://www.cnlopb.ca/</u>).

The Energy Branch ensures that industry follows responsible resource development and management practices for the maximum benefit of the people of the province. To achieve this, the Energy Branch monitors resource development activities to ensure adherence to relevant policy, legislation and regulations and is responsible for the development and administration of royalty regimes for petroleum projects (onshore and offshore). The Energy Branch also administers onshore petroleum exploration and production rights and ensures compliance with site development and rehabilitation requirements.

The Energy Branch is divided into three subdivisions:

- 1. **The Petroleum Development Section** manages the exploration, development and production of the province's hydrocarbon resources by providing technical services in the areas of petroleum geoscience, petroleum engineering and petroleum operations and also provides marketing and promotional services, both nationally and internationally.
- 2. The Royalties and Benefits Section negotiates, develops and administers energy and mines project agreements and royalty legislation/regulations for major resource projects. They also a) negotiate and monitor industrial benefit commitments related to energy and mines resource developments, b) audit petroleum project costs and revenues to verify the accuracy of royalties paid to the province; provide energy-related economic/financial and supply/demand information, analysis and advice to inform resource management decisions, and c) promote the Province's industrial capacity and capabilities.
- 3. The Energy Policy Section develops plans and coordinates legislative, regulatory and policy matters relating to the Province's energy sector, including managing/co-managing onshore and offshore petroleum exploration and development through regulatory development and compliance; electricity industry governance and structure, electricity industry markets, alternative energy, and the *Electrical Power Control Act*, as well as general policy, planning and coordination related to the Energy Sector, including a lead role in the implementation of the Province's Energy Plan.

2.2 Legislative Overview

The DNR manages oil and gas development projects through the administration of legislation and regulations designed to guide and govern mineral and petroleum development. In its role as regulator, the department monitors project activity and performance to ensure compliance with legislative and regulatory requirements, as well as contractual requirements specific to individual projects. The department endeavors to work with industry to assist in interpreting and incorporating these requirements into operations early in the lifecycle of a project. The following legislation and regulations govern hydrocarbon exploration and development in the Newfoundland and Labrador onshore area.

The *Petroleum and Natural Gas Act* defines how the rights to explore for and develop oil and gas properties on land may be obtained and maintained; how areas may be assigned for exploration; the scope with which government may regulate activity and the various royalties that may be due. The Act provides for the following regulations to govern the Province's oil and gas resources.

- *The Royalty Regulations, 2003* outlines the rules for calculating, reporting, assessing and auditing royalty amounts.
- **The Petroleum Regulations** govern the issuance of petroleum rights in the Province's onshore area. The Regulations provide the mechanism whereby government issues onshore rights to explore, drill and eventually produce petroleum. The Regulations allow the minister to, among other things, issue Exploration Licences (*ELs*); offer lands in a Request for Bids (*RFB*) including all terms and conditions; issue Exploration Permits (*EPs*); allow all or part of a permit to convert to a Production Lease (*PL*); approve transfers of specified undivided interests in a permit or lease; and terminate or cancel a licence, permit or lease.
- **Petroleum Drilling Regulations** govern the exploitation and conservation of oil and gas resources through prudent drilling practices for conventional and unconventional resources. The regulations set out what is required to receive approval to conduct onshore drilling operations throughout the drilling and completion of a well.

There are a number of guidelines produced by the Department of Natural Resources in support of the *Petroleum Drilling Regulations*. They are:

- Guideline for Final Well Reports for Exploratory Wells Onshore
- Validating Well for the Purpose of Permit Extension
- Guideline for Final Well Reports for Onshore to Offshore Wells
- Guideline for Drilling Application Submissions
- ADW Application Template (Draft)
- DPA Application Template (Draft)

- Guideline for Information Submission to the Petroleum Exploration Referral System
- BOP Classification System
- Newfoundland and Labrador Exploration Survey Regulations (including Guidelines for Conducting Petroleum Exploration Surveys in the Newfoundland and Labrador Onshore Area) (Draft)
- Newfoundland and Labrador Basis for Development of Guidance Related to Hydraulic Fracturing Parts 1-3 (Draft)

All these documents are available from the Department of Natural Resources website (<u>http://www.nr.gov.nl.ca/nr/energy/index.html</u>).

2.3 Land Tenure Process

Petroleum land tenure involves the Call for Postings process (Figure 2) and the management of the petroleum rights granted as a result of a Request for Bids (RFB). The Call for Postings (CFP) process is the first step companies must make towards obtaining the right to explore, develop and produce petroleum resources.



Figure 2. The onshore land tenure process.

In the Newfoundland and Labrador Onshore area, exploration and production rights are granted via the *Petroleum Regulations* under the *Petroleum and Natural Gas Act*. These rights are issued and managed by the provincial Department of Natural Resources.

In accordance with the *Petroleum Regulations*, the Minister is authorized to issue a **Call for Postings**, inviting interested parties to identify the areas they would like to see made available for exploration in a subsequent Request for Bids. A Call for Postings may be called at any time and will have a set timeframe for the submission of lands. Depending on the level of interest expressed during the Call for Postings the Minister may issue a **Request for Bids (***RFBs***)** for the issuance of Exploration Permits. The Request for Bids indicates those lands available for bidding and the general terms and conditions that would apply to such bids. Bids are assessed based on a single criterion as set out in the Request for Bids document. The single criterion can be a cash bonus bid, a work expenditure bid or any other single criterion chosen by the Minister. In all previous onshore land sales the single criterion has been a work expenditure bid. The work expenditure bid is normally subject to a 20 percent per year expenditure schedule. The first year work expenditure is submitted as a down payment prior to the issuance of an Exploration Permit.

There are three instruments of title that govern petroleum exploration and development activities in the Province:

- 1. <u>An Exploration Licence</u> does not confer any petroleum rights, but confers the nonexclusive right to conduct an exploration survey (e.g. seismic program, acquisition of potential field data, shallow coring, etc.) described in the licence. An exploration licence does not arise from a request for bids, and is valid for one hundred and eighty days.
- 2. <u>An Exploration Permit</u>, issued as the result of a Request for Bids, confers the exclusive right to drill and test for petroleum on designated lands. A permit is valid for a primary term of five years and can be extended for a further secondary term of two years if certain conditions are met. These conditions are set out in the *Petroleum Regulations* and are either, the drilling of a validating exploration well, or the submission of a security deposit along with a commitment to drill an exploratory well during the two-year extension period. If, at the end of the primary or secondary term, a discovery is made, then a permit holder becomes entitled to convert to a Lease all or a part of the Exploration Permit to which the discovery applies.
- 3. <u>A Lease</u>, issued as a result of a discovery on an exploration permit, confers to the lessee the exclusive right to develop and produce a petroleum pool in the lease area. A lease has an initial term of ten (10) years, subject to five (5) year renewals, for those areas still in production or necessary for production. As a pre-requisite to obtaining a Lease, an Exploration Permit holder must submit, and receive approval for, a Development Plan for at least one of the petroleum pools discovered in the Permit area.

Current land situation. The Department has held four (4) previous RFBs in 1992, 1993, 1996, and 2002, resulting in the issuance of forty-four (44) exploration permits. There are currently five (5) Exploration Permits and one (1) Production Lease in force in the Newfoundland and Labrador onshore area (Figure 3).



Figure 3. Current Exploration Permits and Garden Hill South Production Lease in Western Newfoundland (as of spring 2015). Notations are Paleozoic areas with petroleum potential: MB = Magdalen Basin; BSGB = Bay St. George Basin; PAP = Port au Port Peninsula; AB = Anticosti Basin; DLB = Deer Lake Basin; PP = Parsons Pond area; SAB = St. Anthony Basin, all units being part of the larger East Coast of Canada onshore and offshore Paleozoic Maritimes Basin.

2.4 Onshore Royalty Regime

On June 21, 1994, the Province of Newfoundland and Labrador introduced a **Generic Onshore Royalty Regime** which applies to any petroleum resources produced in the Province's onshore areas. The Royalty Regulations, 2003 outlines the rules for calculating, reporting, assessing and

auditing royalty amounts. The general elements of the onshore royalty regime are as follows:

1. Royalty Holiday

There is no royalty payable on the first two million barrels or equivalent of production for a project.

2. Basic Royalty

After two million barrels of production, a Basic Royalty of five percent is payable by the project interest holder(s). The five percent rate is applied to gross sales revenue from the project less eligible transportation costs to the point of sale.

Royalty Structure

Basic Royalty						
	First 2 Million					
Royalty Holiday	Barrels					
Basic Royalty	5%					
Net Royalty						
Tier 1						
Rate	20%					
Return Allowance	5% + LTGBR *					
Tier 2						
Rate	5%					
Return Allowance	5% + LTGBR *					

* Long Term Government Bond Rate

3. Net Royalty

The Net Royalty consists of a two-tier profit sensitive royalty with each tier becoming payable from the project interest holder(s) after recovery of historical project eligible costs including royalty payments plus a prescribed return allowance for each tier. Recovery of historical eligible costs including royalty payments and the prescribed return allowance is often referred to as Net Royalty (Tier 1 or Tier 2) payout.

• Tier 1

When Tier 1 payout has occurred, the Tier 1 Net Royalty becomes payable at 20% of Net Revenue. Net Revenue is calculated as gross sales revenue less transportation costs less eligible capital and eligible operating costs (including uplifts where eligible). Basic Royalty is a credit against this royalty therefore the interest holder(s) essentially pay(s) the higher of Basic Royalty or Tier1 Net Royalty.

• Tier 2

When Tier 2 payout has occurred, the Tier 2 Net Royalty becomes payable at 5% of Net Revenue. Net Revenue is defined as per above. Tier 2 Net Royalty is incremental to Basic and Tier 1 Net Royalty.

3. HISTORY OF ONSHORE WESTERN NEWFOUNDLAND EXPLORATION

3.1 Historic Exploration

Naturally occurring hydrocarbon seeps and shows have been observed along the coastline and inland waterways of Western Newfoundland for the past two hundred years (Figure 4). The earliest reference, which dates back to 1812, was centered around Parsons Pond on the Northern Peninsula. In this area and elsewhere throughout western Newfoundland, hydrocarbon occurrences manifest themselves as live and dead oil shows within various host rocks, as gaseous emissions from surface and subsurface fractures and as petroliferous odours released from freshly broken rock.

Onshore Western Newfoundland has three sedimentary basins capable of generating hydrocarbons (Figures 4 and 5). The Lower Paleozoic Anticosti Basin is the largest at ~13,000 km². Two Upper Paleozoic Carboniferous basins, Bay St. George and Deer Lake, partially overlie the Anticosti Basin towards the east. These basins are both approximately 2,500 km² in overall area. Further to the north along the eastern side of the Northern Peninsula, a small onshore section of the Carboniferous St. Anthony Basin is juxtaposed against the Lower Paleozoic Anticosti Basin.

The historic exploration/drilling phase for Western Newfoundland had its beginning with a well drilled by John Silver at Parsons Pond in 1867 and culminated with the drilling of four shallow stratigraphic test holes by BHP Petroleum Limited at Port au Choix in 1991 (Figure 5). It is estimated at least 64 wells were drilled in this timeframe, none of which were located using seismic data. Wells were spotted adjacent to surface seeps or along topographic irregularities. Over half the wells drilled encountered trace to minor amounts of oil and/or gas and it is estimated 5,000 to 10,000 barrels of oil may have been produced, although no records exist to verify these numbers.

Since 1994, seismic has been the primary tool used for well selection and this date serves to separate the historic and current exploration periods documented in this report. Forty onshore wells, characterized as exploration, delineation or stratigraphic test were drilled from 1994 to 2015 (Figure 5). Some of these failed to penetrate overburden or were abandoned prematurely due to drill related problems. Most of the wells encountered hydrocarbons, but only the Port au Port #1 well and associated sidetracks situated on the Port au Port Peninsula achieved hydrocarbon production; production to date has been approximately 40,000 barrels of oil with associated gas.

In the near offshore of Western Newfoundland, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) reports that nine onshore to offshore wells and one offshore well have been drilled in Western Newfoundland since 1995 (Figure 5).

The numerous hydrocarbon seeps and shows throughout Western Newfoundland demonstrate the presence of at least two active petroleum systems. There is at least one proven, and maybe more, source rock units capable of generating hydrocarbons.



Figure 4. Map of seeps and shows for Western Newfoundland. Notations are Paleozoic areas with petroleum potential: MB = Magdalen Basin; BSGB = Bay St. George Basin; PAP = Port au Port Peninsula; AB = Anticosti Basin; DLB = Deer Lake Basin; PP = Parsons Pond area; SAB = St. Anthony Basin.



Figure 5. Map of recent and historic wells of Western Newfoundland including current Exploration Permits. Notations are same as in Figures 3 and 4.

3.2 Anticosti Basin, Port au Port and Parsons Pond areas

<u>Historic Exploration</u>. Hydrocarbon seeps have been reported from the Parsons Pond area since 1812. In 1867, just eight years after Colonel Edwin Drake's oil discovery well in Pennsylvania, John Silver arrived from Nova Scotia and drilled a 213 m deep well at Parsons Pond. The well intercepted a number of oil and gas bearing horizons. For reasons unknown, Silver departed the region shortly thereafter and no further exploration activity took place until early in the 1890's. At this time, the Newfoundland Oil Company was incorporated in St. John's and over the following ten to twelve years, they and other Newfoundland incorporated companies drilled about ten wells around Parsons Pond. Within the same timeframe, the Canadian-Newfoundland Oil Company drilled one well further south at St. Paul's Inlet and the Western Oil Company sank at least four wells at Shoal Point on the Port au Port Peninsula. Although numerous shows were encountered and sporadic oil production was achieved, all these ventures ultimately failed.

In 1910, J. D. Henry, a British oil expert, came to Newfoundland and conducted an in-depth evaluation of the oil potential around Parsons Pond. In a book titled, "Oilfields of the Empire" Henry gave a glowing account of the area's oil potential, so much so that British capitalists incorporated a number of companies to explore for oil in the region. From 1911 to 1925, at least three British companies operated at Parsons Pond. From available records, General Oilfields Limited under the guidance of J. D. Henry achieved the best success, having in 1922 three wells in the drilling stage, three wells being pumped and one being bailed. Their onsite refinery was producing approximately twenty-five barrels of oil per week. Further to the south at Shoal Point, an unnamed British company drilled at least one well in 1911. After 1925, records indicate there was no further petroleum activity in the region until 1952. From 1952 to 1954, an American company put down two wells at Parsons Pond and three wells at St. Paul's inlet. Hydrocarbon shows were encountered in both areas but drill related problems and a fire which destroyed the field office and records discouraged the company and they left the area.

Another drilling attempt at Parsons Pond took place in 1965, when the Newfoundland and Labrador Corporation (NALCO) put down a well to a depth of 1302 m. The well, Parsons Pond I-65 intercepted ten oil zones having a total net pay of 34.7 m. Geochemical analyses showed the oil to be "sweet" with an API gravity of 43.4[°]. In the same year, Golden Eagle Oil and Gas Limited in conjunction with British Newfoundland Exploration Limited (Brinex) sank two wells at Shoal Point. The Shoal Point #2 well penetrated numerous porous zones with associated trace to fair, live and dead oil shows. The last phase of historic exploration took place in 1991 near Port au Choix on the Northern Peninsula. BHP Petroleum continuously cored four shallow, stratigraphic test holes in order to evaluate reservoir quality within dolostone of the Catoche Formation, St. George Group. Core and field examination suggests the drill holes penetrated an exhumed oil reservoir.

<u>Current Exploration</u>. The first petroleum well to be spotted with seismic and drilled with a conventional rotary rig was on the southwestern side of the Port au Port Peninsula at Garden Hill in 1994/1995 (Figures 4 and 5). This well, Hunt/PanCanadian Port au Port #1, encountered several reservoirs within platform carbonates, one of which was hydrocarbon bearing. The hydrocarbon zone produced over two separate intervals, 1528 and 1742 barrels per day of 51⁰ API oil and 2.6

and 2.3 million cubic feet of natural gas (respectively), plus associated water. An extended test on one of the intervals gave 5,012 barrels of oil over a nine-day period. Subsequent to this discovery, Canadian Imperial Venture Corporation (CIVC) farmed into the project and drilled two sidetrack wells in 2001 and 2002 from the original wellbore. At the same time, CIVC applied for and received a Production Lease for the initial discovery well. Shortly thereafter, CIVC ran into financial difficulties and by 2008 PDIP Production Inc. became the primary operator of the lease. Later the same year PDIP drilled a horizontal well, sidetrack #3 in order to test the productivity of the oil-bearing horizon with increased reservoir exposure. Currently, Enegi Oil is operator for the lease area. The well and sidetracks to date have produced approximately 40,000 barrels of oil and 120 million standard cubic feet of gas. Currently Enegi Oil is the operator of the field (Figure 5).

After drilling Port au Port #1, Hunt/PanCanadian spudded two more wells up to the end of 1996. The first, Long Point M-16 went onshore to offshore while their second, St. George's Bay A-36 was drilled entirely offshore, southwest of Cape St. George. At the same time, Talisman et al. drilled Long Range A-09, an onshore to offshore well located on the coast south of Garden Hill. All three wells had hydrocarbon shows and porous intervals. In 1997, Inglewood Resources commenced but failed to complete the onshore to offshore Man O'War I-42 well on the south coast of the Port au Port Peninsula. Following this activity, PanCanadian et al. spudded the onshore to offshore Shoal Point K-39 well on the tip of Shoal Point in 1999 (Figure 5). The well failed to intercept the intended platform carbonate target and no further activity took place until 2008 at the Shoal Point location.

In 2008, Shoal Point Energy drilled the 2K-39 sidetrack well from the original K-39 site and upon evaluation of data concluded that overlying Green Point shales offered better potential than the original carbonate targets. Shoal Point Energy and partners returned in 2011 and drilled a second sidetrack, 3K-39, to test their unconventional shale oil play concept. No fracture stimulation of the unconventional reservoir was attempted. Results from this drilling suggest that the shales have good reservoir quality and would likely benefit from stimulation using the technique of hydraulic fracturing.

Further to the north in the Bay of Islands, Mobil Oil Canada Properties Ltd. put down a 300 m test hole in late 1997 to determine reservoir properties and source potential of the turbiditic Blow Me Down Brook Formation. The well contained oil stained porous intervals and extracted fluids, upon analyses indicate gravity between 26⁰ to 35⁰ API. Northwards at Parsons Pond, Contact Exploration and partners drilled Parsons Pond #1 in 2004. The well was terminated after encountering a fault zone prior to the planned drill depth. In 2010-11, Nalcor Energy Corporation and its co-venture partners returned to the area and drilled the Seamus #1 and Finnegan #1 wells, targeting Cambro-Ordovician carbonates (Figure 5). Numerous gas shows were encountered in both wells within the thrusted Cambro-Ordovician sequence. However, neither well was tested and they were both abandoned after logging. In 1997, Delpet Vinland spudded Big Springs #1 over an anticlinal duplex structure located near Hare Bay on the Northern Peninsula. The well reached a depth of 1397 m and was subsequently plugged and abandoned.

3.3 Bay St. George Basin

Historic Exploration. The earliest known hydrocarbon shows were documented and published in the "1873 Annual Report to the Colonial Newfoundland Government" by government geologist, Alexander Murray. Following this early work, studies by Hayes and Johnson (1938) and Bell (1948) confirmed some of the early occurrences and described new shows from around the basin. Most of these shows were either gaseous odours, dead oil along fracture surfaces or oil shales. The presence of live oil was not documented until 1956, when the provincial Department of Mines and Energy, while undertaking a delineation drill program on the Flat Bay gypsum deposit, intersected gaseous and liquid hydrocarbons in separate core holes. In core hole 24N0E, natural gas was encountered at a depth of 31.4 m within anhydrites of the lower Codroy Group. This gas had to be flared before drilling could resume. A second hole, 28N4W, designed to penetrate evaporate units and investigate deeper horizons struck petroleum bearing conglomerate at 107.3 m. According to the well geologist, "petroleum droplets oozed from the core along its total 13.1 m length". Nonetheless, no further petroleum related activity associated with this discovery took place at that time. The first well to be drilled exclusively for hydrocarbons was Union-Brinex Anguille H-98 in 1973. It was drilled to a depth of 2311.2 m near the southern end of the basin, primarily as a stratigraphic test to evaluate the hydrocarbon potential of the Anguille Group (Figure 5). No oil or gas shows or suitable reservoir horizons were noted.

<u>Current Exploration</u>. In 1996, London Resources Inc. continuously cored a stratigraphic test hole at Flat Bay in order to delineate the petroleum occurrence first observed by the Department of Mines and Energy forty years earlier while drilling in the area for gypsum. The well verified the 1956 hydrocarbon occurrence. Three years later, Vulcan Minerals Inc. spudded their Flat Bay #1 well adjacent to the 1996 test hole and upon completion, announced the well had penetrated "significant oil shows over a gross interval exceeding 100 metres". Test results indicated sweet oil with an API gravity of 34⁰. Vulcan drilled an additional four wells over the next seven years to delineate the play (Figure 5). This same play was also targeted by American Reserve Energy (Canada) Corporation in 2000 and 2001. The American Reserve #1 well however experienced drill related issues and was terminated prior to intercepting the intended play horizon. In 2005, Vulcan Minerals put down one well to the northeast and another two wells approximately ten kilometres south of their Flat Bay discovery (Figure 5). The southern wells had a number of hydrocarbon shows, mainly in the form of cuttings fluorescence and anomalous gas detector readings.

Between 2009 and 2011, Vulcan Minerals and new partner Investcan Energy Corporation conducted further test hole drilling around the Flat Bay discovery in order to determine pool boundaries and flow viability. Within the same timeframe the partnership drilled two deep target wells, Red Brook #1 to the southwest and Robinson's #1 to the southeast of the Flat Bay anticlinal structure (Figure 5). Both wells encountered numerous gas bearing zones in Anguille Group clastic horizons. The Red Brook well flow tested gas to surface. In 2012, Investcan Energy Corporation acquired a 100% working interest in properties previously held by Vulcan Minerals in the basin. Investcan drilled their Gobineau #1 well at Flat Bay later in the year and then re-entered and deepened an earlier well, Hurricane #2 in 2013 (Figure 5). These wells encountered minor amounts of natural gas and live oil shows within the Anguille Group sandstone. On May 10, 2012 Vulcan Minerals Inc. announced that it had sold its 50% working interest in three onshore exploration permits EP (03-106, 03-107 and 96-105) in the Bay St. George area to Investcan Energy Corporation for \$2.5 million in cash and a 2.5% gross overriding royalty on all future production (Figure 4). Investcan Energy now owns 100% interest in the three permits and has assumed the operator position from Vulcan. Investcan announced that they would be pursuing a four well pilot appraisal program on the tight oil prospect in the area. The program consisted of drilling three oil producers and one water injector. The first oil producer, Gobineau #1 was spud on November 31, 2012 on exploration permit EP 03-106 utilizing Junex's Foragaz #3 drilling rig. The well was completed in 2012 and the company has not proceeded further with the pilot development.

3.4 Deer Lake Basin

<u>Historic Exploration</u>. During the early 1900's, prospectors working independently or backed by British capitalists were actively exploring for oil shale or solid bitumen deposits in the basin. A small, solid bitumen occurrence was reportedly worked west of the Town of Deer Lake at this time. In 1911, the Anglo-Cuban Oil, Asphalt and Bitumen Company were engaged in oil shale exploration and according to company officials the basin shales yielded, upon retort, 40 gallons oil/ton. Another British syndicate dug a series of test pits and drilled two shallow test holes from 1913 to 1915. Results from this activity are unknown, but company officials did claim the shales produced around 30 gallons oil/ton. From 1919 to 1921, the Colonial Oil Shale and Chemical Company under T. Landell-Mills drilled three holes near the Town of Deer Lake. Two of these failed to penetrate overburden. The Mills #1 well penetrated the Rocky Brook Formation down to 230.8 m before a gas blowout terminated operations. No further drilling took place in the basin until 1955, when Claybar Uranium and Oil Limited and Newkirk Mining Company partnered to undertake a four well program. Claybar #1 and Claybar #3 both encountered gas shows in the Rocky Brook and North Brook Formations. Minor oil shows were also reported from the Rocky Brook Formation.

<u>Current Exploration</u>. In 2000, Newfoundland based, Deer Lake Oil and Gas Limited targeted a seismically defined, fault bounded structure on the western side of the basin and continuously cored their Western Adventure #1 well to a depth of 1879 m (Figure 5). The well encountered 1350 m of locally porous, sandstone and conglomerate of the North Brook Formation, a potential reservoir horizon. This horizon flow tested gas at a maximum rate of 100,000 cubic feet per day and produced minor amounts of condensate. As a follow up, the company continuously cored a second well, Western Adventure #2 to 1325 m, approximately six kilometres to the northeast, targeting another fault bounded block within the basin's central flower structure. Minor gas shows were encountered throughout the well. In 2010, Deer Lake Oil and Gas Limited switched their focus to shale gas and drilled Werner Hatch #1 to a depth of 442 m into the Rocky Brook shale formation. In 2013, Black Spruce Exploration Limited purchased 100% ownership of the two Exploration Permits (EP93-103 & EP03-105) held by Deer Lake Oil and Gas in the Deer Lake Basin (Figure 3); basin assessment is underway.

3.5 St. Anthony Basin

The onshore portion of the Upper Paleozoic, St. Anthony Basin is roughly 20 km² in area and comprises two small peninsulas on the eastern side of the Northern Peninsula. Medium to coarse grained clastic sequences on both peninsulas host live and dead oil shows. Finer clastic units show potential for unconventional oil and gas. There has been no onshore drilling in the basin, but based on hydrocarbon occurrences, excellent potential may exist in the near-offshore portion of the basin. The true hydrocarbon potential of this basin lies offshore, where large structural traps are seen in the Paleozoic sequence and combination traps are present in the overlying Mesozoic/Cenozoic post rift sequence.



Photo credit: Michael Enachescu.

4. REGIONAL GEOSCIENCE

4.1 Tectono-Structural Setting

The West Coast of Newfoundland has a well-understood, albeit complex, geological history involving Late Precambrian to Early Paleozoic metamorphic, intrusive and extrusive volcanics and sedimentary sequences deformed during the Appalachian orogenies (Figure 6). Regionally, the evolution of the Appalachian Orogeny involved the opening and closing of the Late Precambrian to Early Paleozoic lapetus Ocean.



Figure 6. Newfoundland regional geology and major tectono-stratigraphic zones (DNR map).

Prior to the Late Triassic opening of the present day Atlantic Ocean, the Appalachian-Caledonian Orogen formed one continuous mountain chain that stretched from the Scandinavian Caledonides in the north through Scotland, Ireland, Eastern Greenland and then over to the North American Appalachians (Williams et al., 1985; Waldron et al., 1998 and 2014; Hibbard et al. 2006; Gibling et al., 2008; Hicks et al., 2009 and 2012; Hinchey, 2014).

The island of Newfoundland contains a well-exposed portion of the Appalachian-Caledonian fold belt and has been divided into four zones based on the lithologic and tectonic characteristics (Williams, 1979; Waldron et al. 1998, Lavoie et al., 2003; Hinchey et al. 2014; Waldron and Hicks, 2014; Figures 6 and 7), these are:

- 1) **The Avalon Zone:** Late Precambrian volcanics and sedimentary rocks are overlain by Cambrian and Ordovician strata. These relatively undeformed Paleozoic rocks have correlatives on the eastern side of the present Atlantic and yield abundant fossils of European affinity.
- 2) **The Gander Zone:** Mainly pre-Middle and Middle Ordovician metamorphosed arenaceous rocks.
- 3) **The Dunnage Zone:** Dominantly mafic volcanic rocks and associated marine sedimentary rocks that overlie an ophiolite sequence. This zone is interpreted to represent vestiges of the lapetus Ocean.
- 4) **The Humber Zone:** Grenvillian granitic basement overlain by a Cambro-Ordovician aged autochthonous and allochthonous section of shallow water platformal sequence and a complex section of deep water shales, source rocks, siltstones, sandstones and igneous deeper water successions.



Figure 7. Paleozoic evolution of the Canadian Maritime Provinces (modified after Lavoie et al., 2003). Arrow indicates the location of Humber Zone where four Paleozoic areas with petroleum potential exist. Notations are NB = New Brunswick, NS = Nova Scotia, PEI = Prince Edward Island and NL = Newfoundland (numbers indicate Million years scale after ICS Chronostratigraphic Chart 2014; <u>http://www.stratigraphy.org/ICSchart/ChronostratChart2014-10.jpg</u>).

4.2 Litho-stratigraphy

The Humber Zone, the area with onshore hydrocarbon potential, is then subdivided into six tectono-stratigraphic, lithologic and tectonic megasequences (Bradley, 1982; Cawood et al., 1988 and 1994; Langdon and Hall, 1994; Knight and Cawood, 1991; Waldron and Stockmal, 1991 and 1993; Williams and Cawood., 1989; Williams, 1995; Cooper et al., 2001; Burden et al., 2001; Calon et al., 2002).

These megasequences are (Figures 7 and 8):

- 1) Siliciclastic Synrift Sediments Megasequence (SRMS) of Late Proterozoic to early Cambrian age, deposited during the opening of the lapetus Ocean
- 2) **Passive Margin Strata Megasequence**, early Cambrian to early Ordovician, consisting of shallow marine carbonates passing seaward into marine shales
- 3) Flexural Forebulge Megasequence (FBMS) of sediments deposited due to the Taconic foreland basin that migrated westward though the region during the late, early Ordovician to the early, middle Ordovician depositing a sequence of subtidal carbonate and shales that were deposited in the early foreland basin
- 4) Culmination of the Taconic Orogeny Megasequence that resulted in the westward overthrusting of basinal sediments, the Humber Arm allochthon, and ophiolites of the Bay of Islands complex. Siliciclastic shallow marine sediments were deposited at this time within the Taconic foreland basin
- 5) **Emplacement of the Taconic Allochthon Megasequence** during the early Silurian Salinic orogeny that caused additional displacement toward the west, and produced exposure and erosion of the metamorphosed hinterland and additional deformation of the eastern Cambro-Ordovician carbonate platform
- 6) **Transtensional Dextral Reactivation Megasequence** of pre-existing basement faults following the compressional deformation of the Late Devonian Acadian orogeny resulting in the creation of successor basins of thick Carboniferous clastics (Deer Lake and Bay St. George basins).



Figure 8. Chronostratigraphic summary diagram of Western Newfoundland Paleozoic strata, Anticosti and Magdalen basins (modified after Cooper et al., 2001; Hinchey et al., 2014 and 2015).



Figure 9. Surface geology compilation map of Western Newfoundland indicating the four onshore petroleum exploration areas: Port au Port Peninsula, Parsons Pond, Bay St. George Basin and Deer Lake Basin (map modified from Hinchey et al., 2014). GMNP = Gross Morne National Park.

Two regions within the Anticosti Basin, the Port au Port Peninsula and Parsons Pond area, and two regions that are part of the Maritimes Basin, the Bay St. George and Deer Lake basins, hold oil and gas potential onshore Newfoundland (Fowler et al., 1995; GNL, 2000; Cooper et al., 2001; Fagan, 2002; Enachescu, 2006, 2011 and 2013; Hicks et al., 2009 and 2012; Dietrich et al., 2011; Waldron et al., 2012 and 2014; Hinchey et al., 2014 and 2015; Burden et al., 2014; Waldron and Hicks, 2014; Figure 9). These areas have been partially covered with regional and detailed seismic reflection data and entirely mapped with potential field data.

4.3 Geophysical Data

Geophysical data coverage in Western Newfoundland consists of: a) relatively sparse and irregular seismic reflection surveys covering mainly the areas with petroleum potential, and b) potential field data recorded over the entire Humber Zone or specific surveys collected over hydrocarbon prospective areas.

Seismic Data

The current regional seismic coverage over the Humber Zone consists of industry and research funded seismic lines, with lines located mostly over the Paleozoic sedimentary areas (GNL, 2000; Fagan, 2002; Waldron and Stockmal, 1991 and 1994; Hall et al., 1992; Waldron et al., 1998; Stockmal et al., 2004; Hinchey et al., 2014; Burden et al., 2014; Figure 10).

The seismic reflection lines in Western Newfoundland were recorded by oil companies mostly during the 1990s when the exploration activity was focused primarily in the Port au Port Peninsula and Parson Pond areas. These lines were initially post-stack migrated. Since that time, some of these lines have been reprocessed to pre-stack time migration and some were depth migrated. However, certain lines have been preserved only in analogue format (paper copies, tiffs, etc.). The most recent lines were recorded during the 2000s in the northern part of the Bay St. George Basin in the Flat Bay area. Areas such as Port au Port and Bay St. George have denser seismic coverage, while others have only a sparse and irregular seismic network. The Deer Lake Basin has only four lines in an area as large as the Los Angeles Basin, which is of comparable size. More information on various seismic programs, data acquisition and processing parameters can be found on the DNR website: (http://www.nr.gov.nl.ca/nr/publications/energy/released_geological_geophysical_reports.html).

Long deep crustal seismic transects were collected in 1989, during the Canada-wide Lithoprobe research program. The Lithoprobe East lines were recorded using the Vibroseis method and crossed several of the Paleozoic areas of the Humber Zone (Quinlan et al., 1992; Marillier et al., 1989 and 1994; Waldron et al., 1998). Memorial University has collected several research lines in the Deer Lake Basin, Parsons Pond and Flat Bay areas. In 2000, under Memorial University's Center for Earth Resources Research operatorship, both a small marine transition zone 3D experimental program and a 2D land line were recorded in the Shoal Point area.

Data quality on the specific lines depends on the complexity of the geology and varies from fair to good. The existing seismic coverage is sufficient for mapping large anticlinal features but is not adequate for mapping structural-stratigraphic or pure stratigraphic traps within the carbonate platform, allochthonous sequences or Devonian-Carboniferous basin fill. It is noteworthy that only



Figure 10. Seismic coverage map of Western Newfoundland sedimentary areas. Red lines show the 2D seismic sections available in SEG Y format; black lines indicate 2D seismic sections available in paper copies or digital image formats. Notations are same as in Figure 3.

Further modern acquisition is needed to delineate and identify new prospects and leads within the Frontier basins of Western Newfoundland. Certain hydrocarbon plays in the region may need 3D seismic coverage to delineate their extent.

the post-1990s wells were drilled using seismic lines for locations and thus can be used to tie the subsurface geology to the regional coverage. Additionally, three onshore to offshore wells (Port au Port #1, M-16 and Shoal Point K-39) and several sidetracks located in the Port au Port Peninsula can be used to correlate source and reservoir rocks in the Humber Zone autochthon and allochthon (Figure 10).

A total of 1270 line kilometres of 2D data have been acquired over the four Western Newfoundland sedimentary areas. A portion of the recorded seismic lines consisting of 542.7 linear kilometres are archived in digital SEG Y format (out of which 162 km will be released at the end of 2015). Another part, comprising 727.3 linear kilometres is archived as paper copies or digital images (alternative format in Figure 10). These data are available to interested parties from the DNR, subject to the confidentiality provisions of the regulations.

Potential Field Data

Gravity and aeromagnetic surveys were acquired over the entire Humber Zone in the search for minerals and hydrocarbon accumulations. Interpolated results can be obtained as a 200 by 200 m grid on demand at no cost from Natural Resources Canada's Geoscience Data Repository (http://gdr.agg.nrcan.gc.ca/gdrdap/dap/search-eng.php).

The Petroleum Exploration Enhancement Program (PEEP) operating through a memorandum of understanding between Nalcor and DNR, funded a high resolution aeromagnetic survey over onshore Western Newfoundland in 2008-09. Total Magnetic Intensity and First Derivative maps covering most of the sedimentary basins of Western Newfoundland are available (Cook and Kilfoil, 2009; Kilfoil and Cook, 2009; Enachescu, 2011 and 2013).

The Geologic Survey of Canada also funded a similar survey covering the Western Newfoundland offshore and onshore areas including the Port au Port Peninsula and Bay St. George Basin. Other aeromagnetic surveys recorded by different exploration groups in the Deer Lake and Bay St. George basins, have been included in a regional Residual Magnetic Field map assembled from all of these surveys (Figure 11). The regional data also include interpolated 1st and 2nd vertical derivative maps of the magnetic field. Profile and interpolated data at a 50 m by 50 m grid, Residual Magnetic Field and Vertical Derivative maps and reports are available from DNR. Aeromagnetic maps allow for more accurate selection of drilling targets, improved location of seismic lines and enhanced interpretation of seismic results.

Links to data and GIS layers are available through NL DNR Geofiles Collection, Geofile Number 012B/0581, NFLD/3075 and NFLD/3076, found at the following government websites:

http://www.geosurv.gov.nl.ca/airborne/disp_airborne.asp?SURVEY_ID=DN09906 http://www.geosurv.gov.nl.ca/airborne/disp_airborne.asp?SURVEY_ID=DN09907 http://www.geosurv.gov.nl.ca/airborne/disp_airborne.asp?SURVEY_ID=DN09908 Results from contiguous offshore aeromagnetic data covering a large part of the western Gulf of St. Lawrence and including the Port au Port Peninsula, flown in 2012 by Nalcor and DNR in partnership with the GSC, are also available online at: <u>http://www.geosurv.gov.nl.ca/airborne/disp_airborne.asp?SURVEY_ID=DN09909</u>

A magnetic gradiometer survey was recorded during the winter of 2005/2006 by Vulcan Minerals Inc. in the northern Bay St. George Basin, Flat Bay area using the AeroQuest Ltd. Tri-Axial magnetic gradiometer system. The data were processed on a 40 m cell grid. The logistics report together with profiles and final maps (at 1: 20k and 1:50k scales) in Geosoft format are available online at: http://www.geosurv.gov.nl.ca/airborne/disp_airborne.asp?temp=n&SURVEY_ID=DN08003.



Figure 11. Map of residual aeromagnetic field data, offshore and onshore Western Newfoundland. The data include public domain government and industry aeromagnetic programs.

4.4 Hydrocarbon Potential

From a petroleum geology point of view, the Anticosti and Magdalen basins belong to the extended chain of Appalachian Paleozoic foreland basins stretching from West Texas to offshore Labrador (Figure 12). These basins have large producing oil and gas fields, from both carbonate and clastic sequences. At the northern end of the basin chain, two gas discoveries were made in the Hopedale Basin, Labrador Sea in Ordovician carbonates.



Figure 12. Appalachian chain of foreland basins including the Anticosti and Magdalen basins of Western Newfoundland, with location of main producing fields and discoveries. ASF = Appalachian Structural Front.

Four prospective hydrocarbon regions, the Port au Port Peninsula and Parsons Pond (Anticosti Basin) and the Bay St. George and Deer Lake Basins (Maritimes Basin), host rich source rocks, clastic and carbonate reservoirs, adequate seals and structural, stratigraphic and combination traps. Only limited petroleum drilling has been performed in the past two decades in these basins. The exploration wells, which have modern log suites and were cored, are listed in Table I and are discussed in this report.

Western Newfoundland Key Wells							
AREA/BASIN	WELL	SPUD	RR	RESERVOIR	DEPTH	DEPTH	NOTES
					(TOP m RT)	(BASE m RT)	
	POPT ALL POPT #1	19/00/100/	07/06/1005		2472	2560	Oildiscovery
		10/09/1994	07/00/1993	COSTA BAY Mbr	3472	2500	Wet good porosity
					3500	3390	Wet good porosity
				CATOCIL	3390	5724	Nutech suggests 887 m of Net Oil Pay within Green Point Em
	LONG POINT M-16	10/00/1005	10/01/1006		850	2050	source rock Reservoired hydrocarbons
		10/03/1333	13/01/1330		030	2350	Significant amount of Green Point source rock Reservoir
							333 m from Nutech report. Quality looks good, petrophysics
	SHOAL POINT 3K-39	18/02/2011	02/08/2011	GREEN POINT	800	1720	confirms moveable hydrocarbons
		10/02/2011	02/00/2011	OREENTOIN	000	1720	
FARSONSFOND							Poor to fair porosity with a number of gas shows that are
	SEAMUS #1	15/02/2010	20/04/2010	EAGLE IS SANDS	1530	1860	related to fracture porosity
	SEAMOS #1	13/02/2010	20/04/2010		2770	2840	Delomite very poor porosity no shows
				WATTS BIGHT	2000	3030	Dolomite, very poor porosity, no shows
				WATTS DIGITI	2900	3030	Sandstone, poor to fair porosity development and minor das
	FINNEGAN #1	09/09/2010	25/11/2010		1070	2250	shows no reservoired bydrocarbons
		03/03/2010	20/11/2010		1370	2230	Poor porosity development in dolomite and limestones, no
					2447	2495	shows
				WATTS BIGHT	2740	2400	Poor porosity development in dolomite, no shows
					27.10	2000	
							Mudstones occasional poor to fair fluorescence with minor
	WERNER HATCH #1	11/02/2010	31/03/2010		20	420	amounts of good fluorescence
		11/02/2010	31/03/2010	ROCKT BROOK	20	420	Siltetonos/shalos, minor staining and well tested at a 840-
							1400 m recovering minor amounts of condensate/water. DST
							#4 1425-1522 m recovered measurable gas to surface at
							$\frac{3}{4}$, 1420 1022 in teopvered medsidable gas to suitable at
							approximately 3000 m /d decreasing to 1000 m /d with
	WESTERN ADVENTURE #1	29/06/2000	17/12/2000	NORTHBROOK	285	1660	gassy muddy water recovery
BAY ST. GEORGE							
		00/00/0000	45/40/0000				Limestone, maristone with laminated annydrite, poor porosity,
	ROBINSONS #1	30/06/2009	15/10/2009	SHIPS COVE	848	872	minor hydrocarbon snows, no gas snows
					0400	0545	Sandstones, poor to fair porosity, minor gas shows no
				FRIARS COVE	2129	2515	Reals madium/dark group and shows interhedded with minor
					2515	2450	Shale, medium/dark grey, gas shows interbedded with minor
	RED BROOK #1	23/10/2000	05/12/2000		2010	3450	Limestone, poor porosity minor gas shows and minor cut
	RED BROOK #1	23/10/2009	03/12/2009		000	097	Sandstones, poor to fair porosity with siltstones and shales
							Detradictiones, poor to rain porosity, with sitistones and sitales,
							Inumerous gas snows, DSTS now gas at up to 257 m /d from
				SPOUT FALLS	897	1765	111 CCC1

Table I. Western Newfoundland onshore and onshore to offshore key wells used in this report.

5. PETROLEUM GEOLOGY

5.1. Port au Port and Parsons Pond Regions, Anticosti Basin

The hydrocarbon potential within the onshore portion of the Anticosti Basin is found within:

1) The allochthonous section of Cambro-Ordovician-aged deepwater clastic sediment that includes the Curling, Cow Head and Northern Head groups, the Lower Head and Maiden Point formations, and

2) The autochthonous Cambro-Ordovician platformal carbonates of the Table Head and St. George groups, and clastics of the Goose Tickle Group (Figures 8, 9, 13 and 14).

Both the allochthonous and autochthonous sections contain source rocks. However, the allochthonous Cow Head, Northern Head and potentially Curling groups contain the highest quality source rocks.

The allochthonous suite of sediments, corresponding to the Humber Arm Allochthon, have been displaced westward by thrust faulting corresponding to the Taconic and Acadian orogenies and are now above their lateral equivalent shelf succession (Williams, 1979, 1985 and 1995; Cawood et al., 1988; Cawood and Williams, 1988; Williams and Cawood, 1989; Stockmal and Waldron, 1990; Waldron and Stockmal, 1991 and 1994; Waldron et al., 1993, 1998 and 2012; Knight, 1996; Cawood and Gool, 1998; Stockmal et al., 1998 and 2004; Burden et al., 2001; Calon et al., 2002; White and Waldron, 2012; Waldron and Hicks, 2014; Figures 13 and 14).

East Anticosti	Port au Port Peninsula	Stephenville & Long Range Cover	
Olcentr Topping Constraint Booker Ollin Ray Steaming McCarlow Trento Sillect Roor Trento Sillect Roor Roadbal	Thick Taconian Foreland Section Tool Trin Chem Hink Inn Cong Point May Paint Fran Group Wirefrows Fran Loonder Fran Loonder Fran	Platform Slices Pinchgut Lake & Old Muns Pond & Floor De Lys she Hend Croop et also Port Gouge Lakendor Group	Hember Am Allochton Layer Head Fin. Cow Head Group Eagle Island Fin. Pojar Fin. Cools Brook/ Cools Brook/ Cools Brook/
2000 m j		Lighthouse Cove	Reluctant Head
	Late Silurian-Devonian Late Ordovician Clastic Wedge (Flysch)	ovician Clastic Wedge 🛛 📓 Continental Slope/Rise Sediments	De Lys South Brook
0 50 km	Carbonate Shelf 📄 Rift and Early Shelf Clastics 🔳 Mafie Vol	leanies Basement	Lady Shipper Pluton

Figure 13. Diagram showing principal stratigraphic units of the Laurentian margin, plotted with thickness on the vertical axis, using the top of the "platform" succession (top of the Table Point Formation) as a datum (after Waldron et al., 1998).

Regional geological studies, systematic geochemical investigations and information obtained from the sparse drilling and seismic surveys conducted by the oil and gas industry, have shown that all the prerequisites for viable hydrocarbon systems are present both onshore and offshore in the Anticosti Basin (Langdon and Hall, 1994; Fowler et al., 1995; Burden and Williams, 1996 and 1997; Williams et al., 1998; GNL, 2000; Cooper et al., 2001; Fagan, 2002; Enachescu, 2006, 2011 and

Hogg, Enachescu et al., 2015
2013; Hicks et al., 2009 and 2012; Dietrich et al., 2011; Waldron et al., 2012; Hinchey et al., 2014; Burden et al., 2014; Waldron and Hicks, 2014). Onshore, with the exception of the Port au Port #1 discovery area, this basin is mostly unexplored and contains "high risk - high reward" frontier type plays in conventional and unconventional reservoirs.





Figure 14. Stratigraphy of the autochthonous and allochthonous sequences forming the Lower Paleozoic Anticosti Basin extending offshore and onshore Western Newfoundland (after Waldron and van Staal, 2001). Unconformities and source and reservoirs rocks are highlighted.

Port au Port and Parsons Pond land areas located just east of the Appalachian Structural Front (ASF) in Figure 12, were the focus regions for petroleum exploration in Western Newfoundland (Section 3). For more than 100 years, the search and drilling for petroleum resources in these two areas targeted the Cambro-Ordovician sandstone and carbonate reservoirs, resulting in several small discoveries. The largest discovery was recorded in 1995, when Hunt et al. drilled and tested up to 1742 bopd of light oil at Port au Port #1, now the Garden Hill Production Lease covering an area of 11 km². More recently, geoscience research and testing without stimulation of unconventional resources occurred within the Green Point Formation of the Cow Head Group in the area around Port au Port Peninsula. As well, two deep exploration wells, Seamus and Finnegan, drilled by Nalcor et al. in 2010/2011 in the Parsons Pond area for sandstone and carbonate reservoirs, encountered gas in low porosity reservoirs and were abandoned without stimulation (Nalcor et al., 2012a and b).

5.2.1 Port au Port Area

The Port au Port exploration area includes the geological formations found in the subsurface of the Port au Port Peninsula, in adjacent shoals and shallow water areas surrounding the peninsula, and in certain small onshore tracts in the Humber Arm (Figures 9, 13 and 15).



Figure 15. Port au Port Area surface geology and location of the exploration wells (modified from Stockman et al., 1998 and Knight et al., 2007b).

Conventional Reservoirs

A number of conventional reservoirs are present in the autochthonous and allochthonous geological sections of the Port au Port Peninsula (Weissenberger and Cooper, 1999; GNL, 2000; Cooper et al., 2001; Fagan, 2002; Hicks et al., 2009 and, 2012; Dietrich et al., 2011; Hinchey et al., 2014 Waldron and Hicks, 2014). As discussed in the History of Exploration (Section 2), the last round of exploration activity that took place during the mid-1980s to mid-1990s, resulted in the acquisition of a significant amount of subsurface information in both the autochthonous and allochthonous geological sections.

During the past decades, these exploration efforts were advanced by several companies trying to develop the Garden Hill South oil field (Port au Port #1 find). Additional geoscience knowledge was gained during recent years (2007 to present) by researchers funded from the PEEP program (http://www.nr.gov.nl.ca/nr/energy/petroleum/onshore/peep.html).

Carbonate Reservoirs. The principal focus for reservoir development on the Port au Port Peninsula has been the autochthonous Cambro-Ordovician-aged carbonates of the Table Head and St. George groups (James et al., 1989; Knight, 1996; Knight et al., 2007a and b; Figure 16). These



potential reservoirs are all shelfal to peritidal carbonates including peloidal packstones to grainstones, thrombolytic boundstones and include the Aguathuna and Boat Harbour formations (Knight and James, 1987; Langdon, 1992; Cowan and James, 1993; Cooper et al., 2001). Dolomitization also plays a role in the formation and preservation of porosity and permeability. Four different types of dolomitization have been recorded in the St. George Group (Haywick, 1984; Azmy et al., 2008; Hulburt, 2011).

Figure 16. Seismic interpreted geological cross-section at the Port au Port #1 discovery well (after Cooper et al., 2001).

In Port au Port outcrops, the majority of dolomitized carbonates have very little remaining primary porosity. There are documented karst features such as breccias described in outcrops of the Aguathuna Formation and shale-filled caves within the Catoche Formation (Knight et al., 1991). In the Port au Port #1 well, the Aguathuna section had good porosity development in dolomite from 3450 to 3475 m of 9.8% over an 18.5 m interval with a permeability of 21 md (Cooper et al., 2001). Within the Catoche section, below the Aguathuna, the well encountered 15 m of 8.7% porosity in dolomites between 3515-3600 m measured depth. The last porous zone in the Port au Port #1 well was found in the Watts Bight Formation between 3915 and 3959 m where logs indicated porosities up to 30% with cavernous porosity encountered.

Several wells in the Port au Port area indicate porosity development within the Aguathuna, Catoche, Boat Harbour and Watts Bight formations. The St. George's Bay A-36 and Long Point M-16 wells were both drilled for these conventional Cambro-Ordovician reservoirs and although considered dry holes, they confirmed the presence of porosity within the carbonate sequences. Petrophysics within the Long Point M-16 well suggest that within the Aguathuna, Catoche and Watts Bight formations there is poor to good porosity development, mostly in dolomites, throughout the drilled 500 m interval (Cooper et al., 2001).

Other Reservoirs. Within the Port au Port #1 well, a secondary reservoir zone was encountered within the middle Cambrian Hawke Bay Formation where petrophysics suggest there is over 60 m of porous quartzarenites with an average porosity of 12%, within the hanging wall of the thrust around 1000 m measured depth. Additional reservoirs are likely to be present in the underlying footwall Lower Cambrian succession, where conglomerates, arkosic sandstones, sandy oolitic limestones and archeocyathid reefs are developed. However, in the areas regarded as favourable for hydrocarbon trapping, these reservoirs would occur at depths that would likely have poor porosity.

Source Rocks

The primary source rock identified from geochemical studies and discussed in the literature is the allochthonous, Cambro-Ordovician aged Green Point Formation of the Cow Head Group (Sinclair, 1990; Fowler et al., 1995; GNL, 2000; Cooper et al., 2001; Fagan, 2002; Bertrand et al., 2003; Enachescu, 2006, 2009 and 2011; Hicks et al., 2012; Hinchey et al., 2014 and 2015; Waldron and Hicks, 2014). The geochemical characteristics of the oil found in natural seeps correlate closely to those of the Green Point Formation. In general, maturity increases in the surface outcrops from west (immature) to east and from south to north (late maturation window) over the Port au Port to Parsons Pond area. It is also suggested that the Green Point shales present north of the Parsons Pond area may reside in the gas window. Thus the best oil generating source rock potential would be in the Port au Port area. In this report the coeval Northern Head Group will be considered as part of the Green Point Formation (Figure 8).

In outcrop, the Green Point shale is heavily fractured and has a book-like cleavage (Figure 17). These natural fractures crisscross the rock layers at various angles, forming an interconnected network throughout the formation. The fractures are likely responsible for the leaking of hydrocarbons out of the formation to the surface, resulting in abundant seeps and shows throughout the Port au Port region (Hicks et al., 2012; Hinchey et al., 2014; Waldron and Hicks, 2014 and Section 3).

The Green Point source rock is Type I/II with total organic carbon as high as 10% (Weaver and Macko, 1988; Fowler et al., 1995). Lithologically, the Green Point Formation of the Cow Head Group includes 400-500 m of interbedded dark grey to black and green ribbon limestone and mudstone with minor interbedded subaqueous limestone conglomerates (James and Stevens, 1986).

Shales of the Green Point Formation sampled at various surface locations in Western Newfoundland include organic-rich, Type I/II, intervals with total organic carbon content up to 10.4% and Hydrogen Indices, HI, up to 759. The Tmax values range from 434-443 C, indicating a thermal maturity below or within the oil window (Nowlan and Barnes, 1987; Weaver and Macko, 1988; Fowler et al., 1995; Bertrand et al., 2003).



Figure 17. Green Point shale in outcrop at West Bay (photo credit: Michael Enachescu).

In the Well History Report for the Shoal Point 3K-39 well, Shoal Point Energy included petrophysical analysis performed by Nutech using their enhanced Nulook technique. The draft report also included assessments of the Long Point M-16 and the Shoal Point K-29, 2K-39Z, and 3K-39 well data (Newfoundland and Labrador Department of Energy, Nutech Petrophysical Analysis report, 2011). Their proprietary shale analysis for the Green Point shale suggests that *"there is a significant volume of hydrocarbon pore volume present in this interval that can serve as the "container" for any hydrocarbons that may be present in the system"*.

Nutech also completed volumetric calculations from the petrophysical data for the Green Point section encountered in the above wells that suggest:

- Up to 915 m (TVD) intersected interval of Green Point Formation contains 333 m of net pay (M-16);
- Storage capacity of almost 380 million barrels of oil-in-place per section;
- Over 593 thousand barrels of oil-in-place per acre across this 915 m (TVD) gross interval.

It must be noted that the Green Point in the Port au Port region is thicker than the normal isopach due to duplexing of the source rock within the allochthon by thrust faulting.

The Nutech study also provides insight into the reservoir properties at the 2K-39 well and predicts moderate permeability for a significant amount of the net pay intervals within the Green Point Formation.

In addition to the Cow Head and Northern Head groups, secondary source potential may exist within shales of the allochthonous, Cambrian aged Curling Group and autochthonous, mid Ordovician Goose Tickle Group. The Curling Group which is generally unfossiliferous consists of black shale, quartzose to arkosic sandstone, conglomerate and red to green shale. Basinal sediments of the Curling Group are coeval with the Labrador Group shelf succession. The Goose Tickle Group consists of a thick sequence of deep water, turbiditic sandstones and organic rich shales.

Sedimentology of the Northern Head Group (Cow Head Group - Green Point Formation equivalent) represents distal slope deposition along the lapetus passive margin. According to Waldron and Hicks (2013), the Northern Head Group has the potential to be a significant petroleum source.

The Geological Survey of Canada (GSC) public Rock-Eval database includes 12 samples of the Green Point Formation with the following characteristics: TOC up to 8.37%, averaging 5.86%; Tmax up to 444, averaging 440; S1 up to 1.73, averaging 1.32; S2 up to 62.06, averaging 34.83; S3 up to 0.53, averaging 0.29; HI up to 753, averaging 613; OI up to 7, averaging 5 (Hamblin, 2006).

Depositional equivalents of the Green Point Formation are present as the Utica Shale of Quebec, New York and Pennsylvania and currently one of the shales being exploited and produced along the Appalachian hydrocarbon trend.

Unconventional Potential of the Green Point shales

With significant net pay thickness, adequate Tmax, and high total organic carbon, the Green Point shale represents the greatest potential unconventional resource in Western Newfoundland.

When trying to determine what is "good unconventional shale" we first need to assess the potential for the shale reservoir to have trapped either gas or oil, and then try to quantify that volume of hydrocarbon.

Also, we need to understand both the type and quality of the hydrocarbons generated and this depends on the kerogen characteristics and their present day maturity. Thus data on the total

organic carbon and the type of kerogen within the shale is important, along with the present day maturity of the source rock, and the porosity and permeability of the shale.

Hinchey et al. (2014 and 2015) have documented the distribution area, thickness, total organic content, reservoir pressure and Tmax vales for the Green Point shale from both publically available outcrop and limited subsurface data. The report suggests that in places, the allochthonous Green Point Formation has the potential to generate significant quantities of oil and gas and production will require hydraulic fracture stimulation.

The other important item to consider is the type of shale matrix and cements. The more silica, calcite or dolomite cement in the matrix, the more indurated the shale and thus the greater the ability to successfully fracture stimulate the reservoir. In frontier basins that are similar to Western Newfoundland, operators will initially drill, core, log and complete vertical wells that are then fracture stimulated with small fractures. This is performed to understand the ability of the rocks to propagate and emplace proppant within the formation and to understand the nature of the flowback and establish a stabilized flow rate for the reservoir (Hinchey et al., 2014). The current scientific and engineering evidence for the Green Point suggests that this formation is a good candidate for stimulation with good quality Type I organic material and a large in-place resource that is presently within the oil window.

Traps

On the Port au Port Peninsula and environs, the primary trap style is related to compressional deformation that produced a number of footwall short cut anticlines (Figure 16). The faults were initially extensional, during the mid to late Ordovician and subsequently reactivated in the Late Silurian, and then further shortening took place in the Late Devonian, (Knight and Cawood, 1991; Lavoie et al., 2003). This structural style also led to porosity enhancement in the subsurface through the development of hydrothermal dolomitization of the Cambro-Ordovician carbonates in proximity to the major thrust faults.

There is also the potential of stratigraphic trapping when the source rock shales are adjacent to distal limestone turbidites. Most of the carbonates have poor porosity, but if they have any effective porosity there is a chance that they could be charged with hydrocarbons.

Seals

There are a number of good quality seals found within the geological column that would allow for hydrocarbons to be successfully trapped. In the allochthonous section, shale acts as both reservoir and seal. In the autochthonous succession, the carbonate porosity development is very localized within several intervals close to regional unconformities. There is good potential of top seal within well cemented Port au Port Group carbonates.

Seismic Data Coverage in the Anticosti Basin

In the Port au Port area of the Anticosti Basin, seven 2D lines (five dip lines and two strike lines) were recorded by Hunt Oil in 1993 (Figure 18). These seismic lines totaling 91 line kilometres are available in both SEG Y and analogue formats. Three 2D regional lines were acquired in 1995 by IEXCO on the roads around the Peninsula adding up to a total of 130 km. During the period July - September 2000, Western Geophysical on behalf of Canadian Imperial Venture Corporation collected 25.7 linear kilometres over the Garden Hill field. The survey consisted of five short NW-SE oriented dip lines and two longer NE-SW oriented strike lines.



Figure 18. Seismic coverage and exploration wells in the Port au Port Peninsula. The lines available in SEG Y format are plotted in red; the lines available only as tiff format or paper copy are plotted in black. The main exploration wells and the Port au Port #1 discovery well are also shown.

The total line kilometres of 2D seismic reflection data for the Port au Port area is 254 km, out of which 115 km are in SEG Y format (Figure 18). Except for the Shoal Point K-39 well, all other exploration wells located in the area were located using the land recorded 2D seismic lines. In 2000, Memorial University of Newfoundland's Centre for Earth Resources Research (CERR), in partnership with several local consultancies, recorded and processed a small 3D transition zone program. This program covers the Shoal Point area where the K-39 well and its sidetracks were drilled.

The current seismic coverage is sufficient for identifying large structural traps in the Carbonate Platform but is not adequate for identifying, smaller autochthon traps, porosity development in the carbonates or for mapping individual thrust sheets of the allochthons.

An example of data quality recorded over the Port au Port Peninsula is given in Figure 19. The seismic line shows the tectonic and structural configuration of the Garden Hill South oil field and includes the projected location of the Port au Port #1 discovery well drilled by Hunt et al. in 1995. The pay zone is located in the St. George Group's Aguathuna formation.



Figure 19. Seismic line showing the approximate location of Port au Port #1 well and structural configuration of the Garden Hill South oil field. Notations are UP = Upper Carbonate Platform including hydrothermally dolomitized Aguathuna reservoir, LP = Lower Carbonate Platform and synrift clastics.

5.2.2 Parsons Pond Area

The Parsons Pond area is located on the Northern Peninsula, north of Gross Morne National Park, west of the Long Range Mountains, and south of Port au Choix (Figures 8 and 20). The area is part of the Lower Paleozoic Anticosti Basin and is generally characterized by low relief topography created by erosion of the Cow Head Group rocks in front of the mountain range.



Figure 20. Regional geology of the Parsons Pond area including hydrocarbon exploration wells (modified from Knight 1985, Williams and Cawood, 1989, White and Waldron, 2012).

Both the allochthonous section of Cambro-Ordovician aged deepwater clastic sediments and the autochthonous Cambro-Ordovician section of platformal carbonates of the Table Head, and St. George groups are present in the Parsons Pond area (Figures 20 and 21). The allochthonous cover thins toward the north where shelf and slope/rise sequences outcrop.

The exploration targets in the area are the Eagle Island sands in the Allochthon and the Aguathuna, Catoche and Watts Bight Dolomites in the Ordovician Carbonate Platform of Western Newfoundland. The expected source rocks are contained in the Cow Head Group including the Green Point shale (Figure 21).

In the Parsons Pond area, the Eagle Island Formation sandstones have fair to good quality porosity and permeability. In the Seamus #1 well the formation has several gas charged intervals. This reservoir is found within the allochthon and the sandstones are generally fine to medium grained, moderately sorted, subangular, mainly quartzose sands with varying amounts of silica and calcareous cement.



Figure 21. Schematic NW-SE geological cross-section of the Parsons Pond area (modified after GNL-DME, 2000 and Fagan, 2002).

Depth

In the Seamus #1 well, there is a minor amount of gas within the fractured carbonates of the early Ordovician Shallow Bay Formation. This would be a very limited reservoir but the gas occurrence suggests that there is upward migration of gas through fractures into the shallow formations. A shallow structural trap may retain sufficient volume of natural gas that could be used for local domestic supply.

A recent integrated fluid inclusion study attempted to constrain the petroleum charge history in the area around Parsons Pond, from the two wells drilled by Nalcor et al. (Conliffe et al., 2013). The study suggests that there have been complex multi-charge events and that the vast majority of hydrocarbon migration is through fractures. Additional findings suggest that no hydrocarbons were present in the low porosity sandstones of the Lower Head Formation and Cow Head Group. The study also confirmed that the Green Point Formation is the most likely source rock for the petroleum present in the Parsons Pond area and that migration took place multiple times during progressive burial and heating (Macauley, 1987; Conliffe et al., 2013). This is clearly supported by one of the samples, CE922.7, which shows an early, low temperature migration of relatively immature hydrocarbons followed by the migration of more mature hydrocarbons, including gas, at higher temperatures (Conliffe et al., 2013).

Seismic Data Coverage in the Parsons Pond Area

Most of the 2D seismic lines in the Parsons Pond area were recorded by Norcen in 1992 and Mobil in 1996. Four strike lines parallel with the shore line and 15 dip lines perpendicular to the shore

are available in the vicinity of Parsons Pond and Portland Creek Pond (Figure 22). Only the research line labelled MUNSIST, is available in SEG Y format. The line was recorded in 2010 using a mini-hydraulic source near the Finnegan #1 well location and followed an older Vibroseis line (89-2)

(http://www.nr.gov.nl.ca/nr/ener gy/petroleum/onshore/PEEP/4a doc16367 munsist.pdf). North of the Parsons Pond area, a multiclient survey (not shown in Figure 22) acquired a regional line crossing the entire Humber Arm, as well as a short line located



north of Port au Choix. The 2D survey totaling 367 line kilometres is archived at DNR and available to interested parties in paper copy or tiff format.

Figure 22. Seismic coverage and exploration wells in the Parsons Pond area. Lines available as tiff format images are plotted in black.

Nalcor has pre-stack time migrated (PSTM) 15 of the area's seismic lines. Several lines were pre-stack depth migrated (PSDM) (Nalcor et al., 2012b). These were used to remap the subsurface structure and locate the Seamus and Finnegan wells, which now provide excellent ties for evaluating further prospects and leads. An example of a PSDM processed seismic line is given in Figure 23. The Nalcor et al. Seamus #1 well penetrated at least two thrust sheets of the Humber Allochthon and then entered the Carbonate Platform including the Aguathuna and Catoche formations.

Figure 23. Portion of PSDM seismic line crossing the location of Nalcor et al. Seamus # 1 well in the Parsons Pond area (modified after Nalcor et al., 2012b).



5.3 Maritimes Basin, Western Newfoundland

There are three subbasins of the Maritimes Basin located along the Cabot Fault system in Western Newfoundland. Even as they are subunits of the Maritimes Basin, these Paleozoic areas are known in literature as basins (Figures 9, 10 and 12). The three basins display marked similarities to each other in their stratigraphy, sedimentology and structural style. The Bay St. George Basin (Knight, 1983) is situated in the southwestern corner of the island of Newfoundland, about 100 km southwestward of the Deer Lake Basin. The lesser known St. Anthony Basin (Howie and Barss, 1975a and b; Haworth et al., 1976; GNL, 2000; Hu and Dietrich, 2010) is mostly an offshore basin, located east of the Great Northern Peninsula.

Each of the basins was formed during Late Devonian to Early Permian by extensional transtension that was associated with dextral strike slip movement along the Cabot Fault system. The basins are dominated by non-marine clastics derived from localized hinterlands filling the accommodation space generated by the fault extension.

5.3.1 Deer Lake Basin

The Deer Lake Basin is a 2200 km² (220,000 ha), strike-slip/wrench intermontane basin situated in Western Newfoundland at the northeastern margin of the Maritimes Basin. It contains Upper Devonian to Upper Carboniferous non-marine successions (Langdon, 1993; Figures 9 and 24).

This successor basin began to form in the Late Devonian through post-orogenic extension (Roliff, 1962; Bradley, 1982; McCutcheon and Robinson, 1987; Hyde et al., 1988; Langdon, 1993; Wright et al., 1996). The basin sits on the remnants of Cambro-Ordovician carbonates and is filled with up to 3,000 m of terrestrial sediments including conglomerates, sandstones and lacustrine shales with moderate to high organic content (Fowler et al., 1997; Kelly and Burden, 2011; Burden et al., 2014; Figures 24 and 25).

The basin was formed in response to strike-slip movements along the Cabot Fault zone in late Devonian to early Carboniferous (Hyde, 1979 and 1984; Hyde et al., 1988). The basin contains a central faulted ridge (flower structure) and two lateral subbasins, Cormack in the west and Howley in the east (Figure 26).

The Deer Lake Basin was enhanced and deformed by strike-slip tectonics through the Carboniferous, with the latest documented deformation occurring in the Late Carboniferous to Early Permian (Belt, 1968 and 1969; Bradley, 1982; Knight, 1983; Langdon and Hall, 1993). Reservoirs and source rocks are coeval with the sediment input and paleo rainfall modified the basin through time, within an active fault-bounded basin.

The lithostratigraphic facies within the basin correlate directly to the interplay of fault-bounded basins subsidence and the rate of sediment input (Hamblin and Rust, 1989; Hamblin, 1992; Hamblin et al., 1997).



Figure 24. Surface geology map of the Deer Lake Basin (modified from Hyde and Ware, 1981; Hyde, 1982; Williams et al., 1983; Knight, 1994; Cawood and van Gool, 1998).

Conventional Reservoirs

Primary reservoir development within the Deer Lake Basin lies within the Visean-aged Deer Lake Group that includes the North Brook, Rocky Brook and Humber Falls formations (Figures 24 and 25). Each formation is controlled by sedimentation related to proximity to the wrench-basin margin. Sedimentation adjacent or close to basin margins resulted in deposition of coarse to fine grained sandstone grading outwards towards the basin center into mudstone and fresh water carbonate, typical of lacustrine deposits. Porosity within the North Brook Formation ranges from 7-9% with fair to good permeability up to the 10 md range (Burden et al., 2014).





Secondary reservoirs are related to the post Visean-aged, Howley Formation. This clastic formation unconformably sits above the Deer Lake Group and is the final fill sequence within the eastern portion of the Deer Lake Basin.

The Howley Formation consists of thick proximal conglomerates and basin center deposited carbonaceous grey sandstones, siltstones, coal measures and non-marine shales (Hyde, 1979).



Figure 26. Schematic west-east geological cross-section over Deer Lake Basin (modified after Hyde et al, 1988 and Fagan, 2002).

Source Rocks

Three source rock intervals exist within the Deer Lake Basin (Figures 24 and 25). The primary and most understood is the Visean-aged Rocky Brook Formation of the Deer Lake Group (Fowler et al., 1997; Kelly and Burden, 2011; Burden et al., 2005). Unconformably below this, lie the Tournaisian-age Saltwater Cove and Forty-Five Brook formations of the Anguille Group (Burden et al., 2014). These Carboniferous formations were deposited within a lacustrine setting in the center of the basin as the sandstones and siltstones infilled the basin from the proximal margin. The Rocky Brook Formation, with source rocks within both the upper grey beds and the lower grey beds, is well documented from surface studies by Hyde (1984) and geochemically by Kalkreuth and Maculey (1989) and Burden et al. (2014) as a Type I lacustrine source rock and Type II with TOC's ranging from 2-5% and max values up to 16%.

The Tmax values in the basin range from 435 to 450°C. Public data obtained from Weatherford and Chesapeake labs on the Warner Hatch #1 well place the source rock in the middle of the oil window. The Hydrogen Index also supports the Rocky Brook Formation residing in the early oil window with values ranging from 100 to 800 mg HC/g C org. Lithologically, the Rocky Brook is a shale. Its thickness, in the basin centre, is suggested to be 800 to 1500 m, although this may not be all good quality source rock. No complete section of the Rocky Brook Formation has ever been drilled. From an extensive review of the available core, Kelly and Burden (2011) state that the Rocky Brook source rocks are laminated and massive dark grey and greyish black shale with a Munsell colour index of N4, N3, and N2. They have attempted to correlate the source beds and TOC relative to the organic values ranging from lean <1% to ~2% TOC for N4 shale and thin beds of N3 shale to ~2% to more than 8% TOC for thick N2 and N3 shale. The Saltwater Cove and Forty Five Brook formations are poorly documented and undrilled in the Deer Lake Basin. Studies suggest that the Saltwater Cove Formation may be as thick as 2500 m and the Forty Five Brook Formation as thick as 1000 m. Within the Saltwater Cove Formation, at the center of the basin, the source rocks will have Tmax values that will place them in the gas window.

Traps

The majority of traps that have been identified in the Deer Lake Basin would be associated with faulted anticlines that result from the depositional to post-depositional wrench movement associated with the Cabot Fault zone (Figure 26). However, there exists the possibility of stratigraphic traps related to the complex fluvial and deltaic filling of the basin by the North Brook Formation, and the younger Howley Formation. Also, there is the potential for similar types of stratigraphic traps within the poorly understood Anguille Group, although this deep section is very difficult to image seismically with the current sparse coverage.

Seismic Data Coverage in the Deer Lake Basin

The Deer Lake Basin has the leanest seismic coverage of all Western Newfoundland's Paleozoic areas. Only seven 2D lines are available in a 2400 km² area (Figure 27). Three lines are dip lines, one is an oblique dip line and three are strike lines (the southernmost line is very short).



Lines 1, 1B, 2, 3 and 4 were recorded by Inglewood Resources in 1997. These lines totaling 37.3 km are available in both SEG Y and analogue formats. Two other lines totaling 11.2 km were recorded in 1994 by Vinland Petroleum and are archived only in paper scanned to tiff format. Both Western Adventure wells were located using the seismic coverage and can be used to tie the geology. The seismic data coverage for the Deer Lake Basin consisting of 48.5 line kilometres is not sufficient to map structural and stratigraphic traps and identify conventional and unconventional reservoirs of this large area (Figures 24 and 27).

Figure 27. Seismic coverage and exploration wells in the Deer Lake Basin. In red are lines available in SEG Y format and in black are lines available as tiff format data.



Figure 28. Uninterpreted strike line over the Deer Lake Basin (Cormack subbasin) (modified after Eyo Ekanem, pers. comm.).

The successor basin's North Brook Formation and the Anticosti Basin's Carbonate Platform are identified on the illustrative seismic line that crosses the Cormack subbasin in a north-south direction (Figure 28). Numerous structural and combination traps can be recognized on this line. However, the data quality is poor as the image was obtained from scanning a paper copy of the seismic section.



Oil stained Rocky Brook Formation Core (Photo Credit: Larry Hicks, DNR).

5.3.2 Bay St. George Basin

The Bay St. George Basin is an onshore arm of the Permo-Carboniferous aged Maritimes Basin that extends under the Gulf of St. Lawrence, between Quebec, New Brunswick, PEI, Cape Breton Island, Nova Scotia and Newfoundland.



Figure 29. Surface Geology map of the Bay St. George Basin and exploration wells (modified from Knight, 1983).

Like the Deer Lake Basin, the basin was initiated during the late stages of the Acadian Orogeny in an extensional setting that included periods of dextral transpression (Williams, 1995). The Bay St. Georges Basin encompasses an area of 2350 km² (235,000 ha) and has a succession of continental sediments up to 10 km in thickness within isolated half-grabens (Figure 29). The succession contains thick deposits of clastics, conglomerates, fluvial and deltaic sandstones, evaporites and minor carbonates resting unconformably on either Precambrian Grenville age crystalline basement or the Mississippian Anguille Group (Figure 30). The sandstone reservoirs of the upper portion of the Anguille Group have the potential to host hydrocarbons derived from the lacustrine source rocks of the Snake's Bight Formation.



Figure 30. Carboniferous lithostratigraphy of the Bay St. George Basin (after Knight, 1992).

Conventional Reservoirs

The main reservoirs within the Bay St. George Basin are fluvial to deltaic sandstones of the Codroy and the Barachois groups (Figures 29 and 30). These two groups represent more than 3000 m of sediment fill within the basin. The lower portion of the Codroy Group is comprised of a basal succession of limestone, gypsum and halite, with interbedded fine grained, poor reservoir quality clastics overlain by red beds and limestones. There is also potential to have vuggy algal laminites and biohermal buildups within the lower Codroy Group and these buildups can have porosity developed in either limestone or dolomite. The middle and upper Codroy Group is dominated by conglomerates and fluvial clastics on the proximal margin grading to fluvial/deltaic sediments toward the center and lacustrine mudstones in the basin center. The secondary potential is within the Anguille Group clastics that are comprised of both conglomerates and coarse grained sandstones.

Porosities within the wells drilled to test the Anguille Group sandstones are in the range of 5-12 % within the Flat Bay area where wells encountered conglomerates of the Friar's Cove and Fishells Brook formations.

Source Rocks

There are a couple of potential source rocks within the Bay St. George Basin. The primary source rock within the Mississippian-aged Anguille Group is the Snake's Bight Formation. This lacustrine shale is coeval with the Horton Group in New Brunswick and has been recognized in the Bay St. George Basin by Knight (1983) who ascertains that the Snake's Bight Formation is nearly 1000 m of thick black shale, grey siltstone, sandstone and dolomites and has TOC's ranging from 1.29 to 1.85%. The formation is most likely well into the gas window in most of the basin, with reported S1 and HI values suggesting most of the kerogen has been converted to hydrocarbons. There is a suggestion that the Ship Cove Formation may contain algal laminates that could generate hydrocarbons and within the shallow Barachois Group there are lacustrine oil shales with TOC's ranging up to 30% but most of them are probably immature source rocks. The Barachois group source rock has been investigated by Solomon (1986). The oil shales are thin and thermally mature, with hydrocarbon yields up to 90 litres/tonne. The kerogen is dominantly Type III, with lesser amounts of Type I and Type II. The Barachois Group also contains mature, organic-rich shales with TOC values of up to 31.9%, suggesting that it is a potential gas source within the basin (Solomon, 1986).

Traps

Traps within the Bay St. George Basin should generally be related to pure stratigraphic and stratigraphic structural configurations (Figures 29 and 30). The most prominent feature in the basin is the Flat Bay anticline which has the ability to produce updip stratigraphic plays within the sandstones of the Codroy and Anguille groups. Also present are structures related to the wrench faulting associated with the movement along the Cabot Fault system (Figure 31). Deeper in the geological section, there are potential biohermal build ups within the Ship Cove and Codroy Road

formations that have the potential to host hydrocarbons and be sealed by the overlying evaporites. And finally, there may be a potential for both oil shale and shale oil (retort).





Seismic Data Coverage in the Bay St. George Basin

Most of the 2D seismic lines in the onshore Bay St. George Basin area were recorded during the past decade by Vulcan Minerals. The lines are located mostly over the surface mapped Flat Bay anticline situated in the northern part of the basin. Eight long strike lines, parallel with the shore line and more than 20 dip lines are available in the basin (Figure 32).



Figure 32. Seismic coverage and exploration wells in the Bay St. George Basin. Lines available in SEG Y format are plotted in red; lines available as tiff format images are plotted in black.

The 2D seismic lines total 309 line kilometres and are archived at DNR. The majority of the lines representing 224 line kilometres are available to interested parties in SEG Y format: while the remaining 85 line kilometres are available only in paper copy or digital image format.



Figure 33. Representative dip seismic section over the Bay St. George Basin.

The strongest seismic marker in the basin is the Base Codroy Formation (Figure 31). As well, the representative line shows a half-graben like basin flanked to the west and east by two basement highs. The highs and the graben are separated by two complex flower structures.

All post-1994 wells in the basin were located using seismic data. However most of the well locations were selected only on a single seismic line. The southern part of the basin is practically unexplored, with no seismic recorded and only one historic well (Figure 29).



Clastics of Codroy Group, Bay St. George Basin (Photo Credit: Larry Hicks, DNR).

6. ESTIMATES OF RESOURCE POTENTIAL

Estimating the resource potential for the hydrocarbon basins of Western Newfoundland is a challenging task. The Paleozoic basins are in the frontier stage; underexplored and poorly understood in the subsurface. Moreover, the number of modern wells with good quality geophysical logs is limited and finally, other than the limited production at the Garden Hill oil field, there are no producing fields or significant discoveries in Western Newfoundland.

For this report we use an approach that takes into account the main reservoirs within each of the basins and then apply ranges to the various reservoir parameters: porosity, water saturation, reservoir thickness, prospect area, oil formation volume factor, Boi, and recovery factor for the conventional reservoirs (Table II).

For the unconventional reservoirs, where even less data exists from only a handful of wells, we apply ranges for porosity, water saturation, reservoir thickness, prospect area and oil formation volume factor, Boi, but we do not attempt to apply a recovery factor. Thus, the generated volumes from these parameters should be considered undiscovered, original oil in-place, resource estimate for the specific shale system.

6.1 Port au Port

In the Port au Port area of the Anticosti Basin, the exploration focus is on five conventional reservoirs, the Ordovician St. George Group carbonates (Aguathuna, Catoche, Boat Harbour and Watts Bight) and the Cambrian Hawke Bay Formation sandstones (Figures 8 and 13 to 19; Tables I and II).

There are a number of wells that penetrated these reservoirs and allow for the identification of a reasonable distribution range for the resource parameters (Table I). The significant challenge on the Port au Port Peninsula is the estimation of the number of remaining drillable prospects. We used a log normal prospect distribution function in order to estimate the remaining number of prospects. This prospect area distribution together with the applied ranges of the other parameters from a P₉₀, a 90% probability of finding at least this value, to a P₁₀, a 10% probability of finding this value, for each of the variables will provide a range of recoverable resource values. It is important to realize that the range distribution should always be tied to risking the chance of success for each of the prospects.

For the potential oil shales within the Green Point Formation, we make an assumption that the area of in-place resource is what is limited to drilling wells onshore and onshore to offshore, with a maximum reach of 5 km from the shoreline and beginning at a depth of 1000 metres below the surface. With positive economics, the distance from shore could be more than doubled. Ultimately, the quality of the reservoir, the cost of drilling and the price of oil will dictate how far industry is willing to drill from shore to reach this resource.

Western Newfoundland Basin Assessment Parameters															ers
Anticosti Basin															
Port au Port Conventional		Reservoir	Product Porosity (%)		Net Pay (m)		Area (ha)		Sw (%) Boi		oi	RF (%)		Key Risks	
			Probability	10	90	10	10 1	0 9	90	10 90	10	90	10	90	-
Aguathuna		Dolomite	Oil	12*	7	25	10 2	0	5	25 50			20	15	Presence of Hydrothermal Dolomite, diagenesis at the unconformity, potential vuggy to cavernous porosity >30%
Watts Bight		Dolomite	Oil	15*	7	25	10 2	:0	5	25 50			20	15	Presence of Hydrothermal Dolomite, diagenesis at the unconformity, potential vuggy to cavernous porosity >30%
Hawke Bay	shallow/hanging wall	Sandstone	Oil	14	8	80	20			25 50			20	15	Porosity degradation if in footwall of thrust faults
Port au Port Unconventional		Reservoir	Product Porosity (%)		Net Pay (m) Are		ea (ha)		Sw (%)	OOIP					
			Probability	10	90	10 9	10 1	0 9	90	10 90	10	90			
Green Point		Shale	Oil	12	8	200	50			45 75					 High Vsh relation to Sw, bound to mobile water; Total porosity vs. effective porosity
Parsons Pond Conventional		Reservoir	Product Porosity (%)		Net Pay (m) Are		ea (ha)		Sw (%)	Boi		RF (%)			
A			Probability	10	90	10 :	10 1	0 9	90	10 90	10	90	10	90	
Aguathuna	hydrothermal	Dolomite	Gas	10	6	50 2	20	_	_	30 50					Lack of porosity without a hydrothermal event
Eagle Island		Sandstone	Gas	8	6	100	20		_	25 50					Presence of trap
Parsons Pont Unconventional		Reservoir	Product	Porosi	ity (%)	Net Pay (m	A	ea (ha)	-	Sw (%)	00		RF		
Cow Head Group		Shale	Oil	10	90	50	20	0 9		35 60	10	90	10	90	Unproven resource, large risk that the shale reservoir is in the dry gas window in the region
Maritimes Basin	entaio	0							00 00						
Deer Lake Basin Conventional		Reservoir	Braduat Barasity (9)		Not Pay (m	Not Days (m)			Sur (9()			DE	(%)	Key Risks	
		Reserven	Probability	10	90	10	0 1	0 9	20	10 90	10	90	10	90	Ney Nors
North Brook		Sandstone	Oil	9	5	40	10			30 50					Very little data, limited seismic, complex basin fill history and trapping configurations
North Brook		Sandstone	Gas	9	5	40	10			30 50					Basin centre, liquids, ngl's and natural gas
Deer Lake Basin Unconven	tional	Reservoir	Product	Porosi	ity (%)	Net Pay (m	A	ea (ha)		Sw (%)	oc	DIP			
Rocky Brook		Shale	Probability	10	90	80	20 1	09	90	10 90 30 60					Limited borehole data, area poorly understood. Most likely in the liquid to gas window vs. oil window in majority of the basin depocentre
Bay St. George Basin Conv	rentional	Reservoir	Product	Porosi	itv (%)	Net Pav (m	A	ea (ha)		Sw (%)	В	oi	RF	(%)	
<u> </u>			Probability	10	90	10	90 1	0 9	90	10 90	10	90	10	90	
Anguille Group		Sandstones	Oil	12	6	40	10			30 60			10	5	Poor to fair reservoir quality, difficulty to determine where best reservoirs exist in the subsurface. Current wells are showing signs of gas, subpressured. Best play would be a stratigraphic trap, risk is very high
Bay St. George Basin Unco	nventional	Reservoir	Product	Porosi	ity (%)	Net Pay (m	A	ea (ha)		Sw (%)	00	DIP		1	
Snake's Bight		Shale	Probability Oil?	10	90 ?	10 ? ?	90 1 ?	<u>0</u> 9	90 ?	10 90 ?					Not enough data to determine the parameters at this time

 Table II.
 Western Newfoundland onshore parameters for resource assessment.

6.2 Parsons Pond

In the Parsons Pond area of the northern Anticosti Basin, there are two recently drilled wells that we used to understand the conventional targets (Figures 8, 20 to 23; Tables I and II). Although no commercial success was recorded, these wells encountered fair to good porosity and permeability in the Cambrian-age Eagle Island sandstones. The key carbonate reservoirs, Aguathuna and Watts Bight, had very little porosity development in recent wells. We assume in our reserves assessment that if a carbonate reservoir prospect is located close to a major fault system, as seen in the Garden Hill oil field, the porosity distribution would be similar, but then the risk of porosity development would be much higher within this region.

We have assessed the potential for two conventional reservoirs in the Parsons Pond area, the Aguathuna and the Eagle Island formations (Table II). We recognize that if hydrothermal dolomitization is proven in the Aguathuna Formation, other Cambro-Ordovician carbonates may also have enhanced porosity development and the potential to trap hydrocarbons.

For the unconventional play in the Parsons Pond area we have reviewed the resource potential of the source rocks of the Cow Head Group. Drilling and surface mapping show that these shales are not as extensive as they are to the southwest in the Port au Port area.

6.3 Deer Lake Basin

In the Deer Lake Basin two conventional reservoirs have the potential to host hydrocarbons (Figures 24 to 28; Tables I and II). The North Brook Formation sandstones of the Deer Lake Group were deposited within the basin as fluvial to deltaic systems that are juxtaposed against and lithostratigraphically below the lacustrine source rocks of the Rocky Brook Formation. The North Brook sandstones are fine to medium grained, arkosic, with poor to fair porosity in the few wells that drilled through the reservoir. The second zone of potential is within the sandstones of the Howley Formation that overlie the Rocky Brook source rocks.

The primary unconventional reservoir within the Deer Lake Basin is the Rocky Brook Formation (Table II). This source rock contains TOC values averaging from 2 to 5% and total porosities ranging from 5-7%. This source rock has intervals with much higher TOC values and thermal maturity indicators place the formation within the top end of the oil window down to the early gas window.

The assessment of the in-place resource potential undertaken in this report is based upon a) limited petrophysical data of the wells drilled and seismic acquired to date and b) the position of the unconventional reservoir at minimum 1000 metres below the surface.

6.4 Bay St. George Basin

Within the Bay St. George Basin, sandstones of the Anguille Group represent the best potential for reservoir (Figures 29 to 33; Tables I and II). These Anguille sandstones were deposited into the Carboniferous successor thick succession of conglomerates and sandstones. The sandstones encountered in drilling to date have poor to fair reservoir properties with average porosities of 5-12% and in a few instances with ranges as high as 15 to 18%. If the sandstone is found to contain an oil or gas pool it may need fracture stimulation to produce at economic rates. There have been a number of documented sandstones encountered in the shallow exploration drill holes that bleed oil out of very low porosity, 2-4%, reservoirs (Vulcan, Final Well History Reports in the Flat Bay wells)

(http://www.nr.gov.nl.ca/nr/publications/energy/final_well_report.html).

Secondary reservoir potential may exist within sandstones of the Codroy Group located along the eastern side of the basin adjacent to the Cabot Fault. In this area, Codroy Group clastics should be buried deeper due to the asymmetric nature of the basin and possibly sealed by carbonate beds of the Codroy Group or overlying shales of the Barachois Group.

There is also potential for an unconventional play within the Snake's Bight Formation, but due to the sparse seismic coverage and limited well penetrations, there is not enough data to evaluate this play. At the unconformity surface, sporadic porosity and permeability development occurs within the Ship Cove limestone.



Hydrothermal Dolomite in Table Point Formation (Photo Credit: Larry Hicks, DNR).

7. PROSPECTIVE PLAYS

There are a number of conventional play types that are viable exploration targets in Western Newfoundland (Weaver and Macko, 1988; Sinclair, 1990; Fowler et al., 1995; Weissenberger and Cooper, 1999; GNL, 2000; Fagan, 2002, Stockmal et al., 2004; Knight et al., 2007; Lavoie et al. 2009 and 2014; Hicks et al., 2009 and 2012; Dietrich et al., 2011; Waldron et al., 2012 and 2014; Hinchey et al., 2014 and 2015; Table II).

After several wells were drilled by major operators in the early 1990s on the Port au Port Peninsula, there has been a long exploration hiatus. Work has continued sporadically by small and independent operators in the Garden Hill field with the drilling of several sidetracks from the discovery wellbore, Port au Port #1 (PAP#1). The first sidetrack, ST#1 was kicked off out of the original wellbore to the northwest in order to penetrate the Aguathuna Formation updip of the original discovery (Figures 15 to 19). The sidetrack was unsuccessful due to the lack of dolomitization of the reservoir.

The only discovery well in Western Newfoundland in modern time, PAP#1, encountered hydrothermal dolomites in the Aguathuna carbonate that were dolomitized and karstified (Cooper et al., 2001; Azmy et al., 2008; Figure 16). This hydrothermal dolomite play type has the potential to be present onshore in other locations along the Port au Port area and especially associated with the Round Head fault complex.

There is an overwhelming need for a new, modern seismic acquisition program (dense 2D or true 3D) on the Port au Port Peninsula in order to continue the exploration efforts for this structural/hydrothermal play. We would suggest that there may be as many as five additional traps in this play trend ranging in size from 5 to 20 ha.

The other attractive play in the Port au Port region is the Green Point Formation (Hinchey et al., 2014 and 2015; Figures 14 and 16). The original Port au Port K-39 well was drilled to test both the potential of the Aguathuna Formation and to collect data on the Cambro-Ordovician Green Point Formation as a potential shale oil reservoir. The data collected from the K-39, 2K-39, 3K-39 and Long Pont M-16 wells strongly suggest that there are a number of zones within the Green Point Formation, that appear to have unconventional potential for light gravity oil (Hamblin, 2006; Nutech, 2011; Hinchey et al., 2014 and 2015).

The Green Point Formation will require hydraulic fracture stimulation for pilot or commercial production and at this time the Province has a pause on hydraulic fracturing (<u>http://www.releases.gov.nl.ca/releases/2014/nr/0811n07.aspx</u>).

In the Parsons Pond region, the two recent wells drilled by Nalcor and partners, of which the results are now in the public domain, show that the allochthonous Eagle Island Formation sandstones exhibit fair reservoir quality within the upper portion of both wells and show minor amounts of gas while drilling, mostly associated with fractures (Nalcor, 2012a and b). The potential exists in the area to find this reservoir with better porosity and permeability within

thrust anticlines and if the stacked reservoirs are charged this could lead to a significant onshore natural gas discovery. The autochthonous Cambro-Ordovician carbonates had little effective porosity observed in the two wells. However, this does not rule out the potential for hydrothermal dolomitic enhancement of the porosity in the vicinity of major thrust faults. A dense 2D modern seismic grid or 3D survey is required to help minimize the risk on structure and detection of fault and fluid enhancement of carbonate porosity.

The early discovery of oil in the Parsons Pond area may also lend itself to a fractured reservoir play using horizontal well techniques to intersect the fractures and produce the oil. The rocks in this section contain very poor natural porosity and the previous production relied on fracture systems within the Cow Head Group.

In the Deer Lake Basin, the North Brook Formation has the potential to trap both oil and gas. Risks are related to source rock maturation and timing of migration (Figures 24, 25 and 27). The structures present in the basin are most likely associated with the major Cabot transtension fault, the central basinal faulted ridge and the ancillary fault systems. Potential traps include structural and structural/stratigraphic plays associated with transpression and syntectonic deposition of the proximal sandstones filling the accommodation space and inter-fingering with the fine grained, playa lake systems. Additional seismic data acquisition is necessary to help confirm any potential structural or structural/stratigraphic plays.

The unconventional petroleum potential of the Deer Lake Basin exists in the Rocky Brook Formation lacustrine shales (Figures 24 and 25). The Rocky Brook source rock is thick and has multiple intervals of high organic content, which are in the oil to liquids rich window. The adequate depth and petrophysical properties of this source rock place it in a favourable position to be tested as an oil or gas/liquids reservoir if hydraulic fracture stimulation was authorized in the province.

In the Bay St. George area of the Maritimes Basin the most likely potential play types are structural, stratigraphic or combination plays within the Anguille Formation sandstones (Figures 28 and 29). The current drilling and outcrop data suggest that there is a marginal, but active petroleum system in the area characterized by the presence of a poor to fair quality reservoir. The complexity of the basin due to the salt and basement tectonics makes it very hard to find the optimum traps without additional high resolution seismic acquisition. A stratigraphic trap may work on the east side of the basin, below the salts and carbonates which could act as good quality top seals.

8. CONCLUSIONS

The province of Newfoundland and Labrador has a long history of intermittent onshore petroleum exploration and oil production. Less than nine percent of the onshore basin lands are currently under licence leaving large tracts of oil and gas prospective areas available for exploration. All of the onshore activity falls under authority of the Government of Newfoundland and Labrador Department of Natural Resources, Energy Branch.

The present Royalty regime is detailed in Section 2 of this report. The Generic Onshore Royalty consists of a 2 million barrel or equivalent royalty on the first production from a project, a basic royalty of 5% and a two-tier profit sensitive royalty which becomes effective when a return allowance of 5% plus the Long Term Government Bond Rate is achieved. Government continues to encourage exploration by ensuring a competitive fiscal regime and effective regulatory structure are in place.

Found as both onshore and offshore areas, the Paleozoic aged Anticosti and Maritimes basins are extensive in the Western Newfoundland region. The exploration activity has focused on Port au Port and Parsons Pond early Paleozoic areas of the Anticosti Basin, and the Bay St. George and Deer Lake areas of the Maritimes Basin. Numerous geological studies of these basins strongly suggest the existence of several working petroleum systems, in all of these basins. These basins all suffer from a limited number of modern exploration wells and poor to incomplete seismic coverage, but present a number of exploration opportunities in both conventional and unconventional reservoirs. Most of the historic and modern wells drilled in the four sedimentary regions of Western Newfoundland have encountered oil and gas shows (http://www.nr.gov.nl.ca/nr/energy/petroleum/onshore/SOW_public_March10_2015.pdf).

The hydrothermal dolomite (HTD) play within the St. George Group is present in the Anticosti Basin and relies on migration from quality mature source rocks in the allochthonous thrust sheets. Carbonate sequences of similar age and setting were found to be highly productive elsewhere in the North American Appalachian trend. The HTD structural-stratigraphic traps are hard to identify and map with the present irregular 2D seismic coverage but there is good potential for light oil accumulations in sizeable structural-stratigraphic traps.

The unconventional reservoirs of the Green Point shales, particularly on the Port au Port Peninsula, appear to have very good petrophysical properties and potential to flow oil and gas if the reservoir is stimulated by hydraulic fracturing. The Province is currently addressing the concerns of hydraulic fracture stimulation by instituting a pause on any projects that include hydraulic fracture stimulation until an independent review of the stimulation technique is completed, a report is made public and recommendations forwarded to the Minister of Natural Resources for consideration. The report will be submitted to the Minister when completed (http://www.releases.gov.nl.ca/releases/2015/nr/0416n07.aspx).

Other conventional and unconventional hydrocarbon plays have been demonstrated to exist. As shown in the seismic data, there is no lack of structural or subtle hydrocarbon traps in Western Newfoundland. However the few modern wells might not have targeted them in the right area with porosity development or where the source rocks were in the optimal maturity range.

Seismic data coverage over the four sedimentary areas in western Newfoundland is limited to 1270 linear kilometres of 2D seismic reflection data. Little of the data is reprocessed to modern standard and the coverage is irregular and containing many short lines. Pre-stack depth migration of data is needed to image the allochthon and autochthon subsurface geometry and map significant horizons. Although there is complete coverage of regional gravity and aeromagnetic data, there is still a need for additional seismic to better understand the structural complexities and the distribution of both conventional and unconventional reservoirs within the basins.

With only 25 true exploration wells drilled in the past 20 years in an 18,000 km² landmass, the Western Newfoundland basins remain a frontier exploration area that provides excellent petroleum resource prospects to seasoned operators with available funds for new seismic data collection and exploration drilling in a truly North American under-explored basin.

The commitment of the Government of Newfoundland and Labrador to the exploration efforts has been ongoing since 2007 with the release of the provincial Energy Plan. This plan was designed to encourage and promote onshore and offshore exploration within the province. For the onshore, this translated into the creation of the Petroleum Exploration Enhancement Program (PEEP) that allocated five million dollars of funding directed towards new studies including source rocks, regional mapping, aeromagnetic surveys and a large study compiling decades of work that has been completed in the basins.

It is estimated that oil and gas and support activities contributed \$9.0 billion to nominal GDP in 2012, representing 28.2% of total provincial GDP. The Province actively encourages exploration in both offshore and onshore areas. There is a robust regulatory regime in the exploration for oil and gas in Western Newfoundland including strong drilling, operations and HS&E regulations. While the Provincial Government encourages petroleum exploration, the safety of workers and protection of the environment are paramount.

Like many underexplored basins, the basins of Western Newfoundland have provided an intriguing glimpse into a number of plays within the various subbasins that are not yet fully understood. Potential resources based upon probabilistic ranges show that with success, Western Newfoundland can be a profitable region for the energy industry. The region has a competitive fiscal regime and potential plays are located close to deep water ports providing year-round access to markets.

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