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Shoal Point Energy Ltd.

Resource study

West Coast Newfoundland

Exploration Licenses 1070, 1120, and 1097R

Effective date: March 31, 2012

ajm Deloitte.

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May 1, 2012

Shoal Point Energy Ltd.
Suite 510, 65 Queen Street West
Toronto, Ontario
M5H 2M5

Attention: Mr. George Langdon

RE: Shoal Point Energy Ltd.
West Coast Newfoundland

At your request and authorization, Deloitte & Touche LLP ("AJM Deloitte") has evaluated the oil and gas resources located in the West Coast Newfoundland area, effective March 31, 2012. This report has been prepared for Shoal Point Energy Ltd. ("Shoal Point").

This report documents the results of our independent evaluation of the total un-risked prospective resource volumes. These volumes were estimated using stochastic techniques. The extent and character of ownership and all factual data supplied by Shoal Point Energy Ltd. were accepted as presented (see Representation Letter attached within).

This report contains forward looking statements including expectations of future capital expenditures. Information concerning resources may also be deemed to be forward looking as estimates imply that the resources described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e. operational risks in development, exploration and production; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of resources estimates; the uncertainty of estimates and projections relating to costs and expenses, political and environmental factors), and commodity price and exchange rate fluctuation.

A Boe conversion ratio of six (6) Mcf: one (1) barrel has been used within this report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

This report has been prepared for the exclusive use of Shoal Point Energy Ltd. This report is not to be reproduced, distributed or made available, in whole or in part, to any other person, company, regulatory body or organization without the complete content of the report and the prior knowledge and written consent of AJM Deloitte. AJM Deloitte hereby gives its consent to the use of its name and to the said estimates pursuant to Part 5 Section 5.7 Item (2) of NI 51-101.

AJM Deloitte is independent of Shoal Point Energy Ltd. as provided in the standards pertaining to the estimating and auditing of oil and gas resource information included in the Canadian Oil and Gas Evaluation Handbook, set out by the Society of Petroleum Evaluation Engineers ("SPEE") and the Association of Professional Engineers and Geoscientists of Alberta ("APEGA").

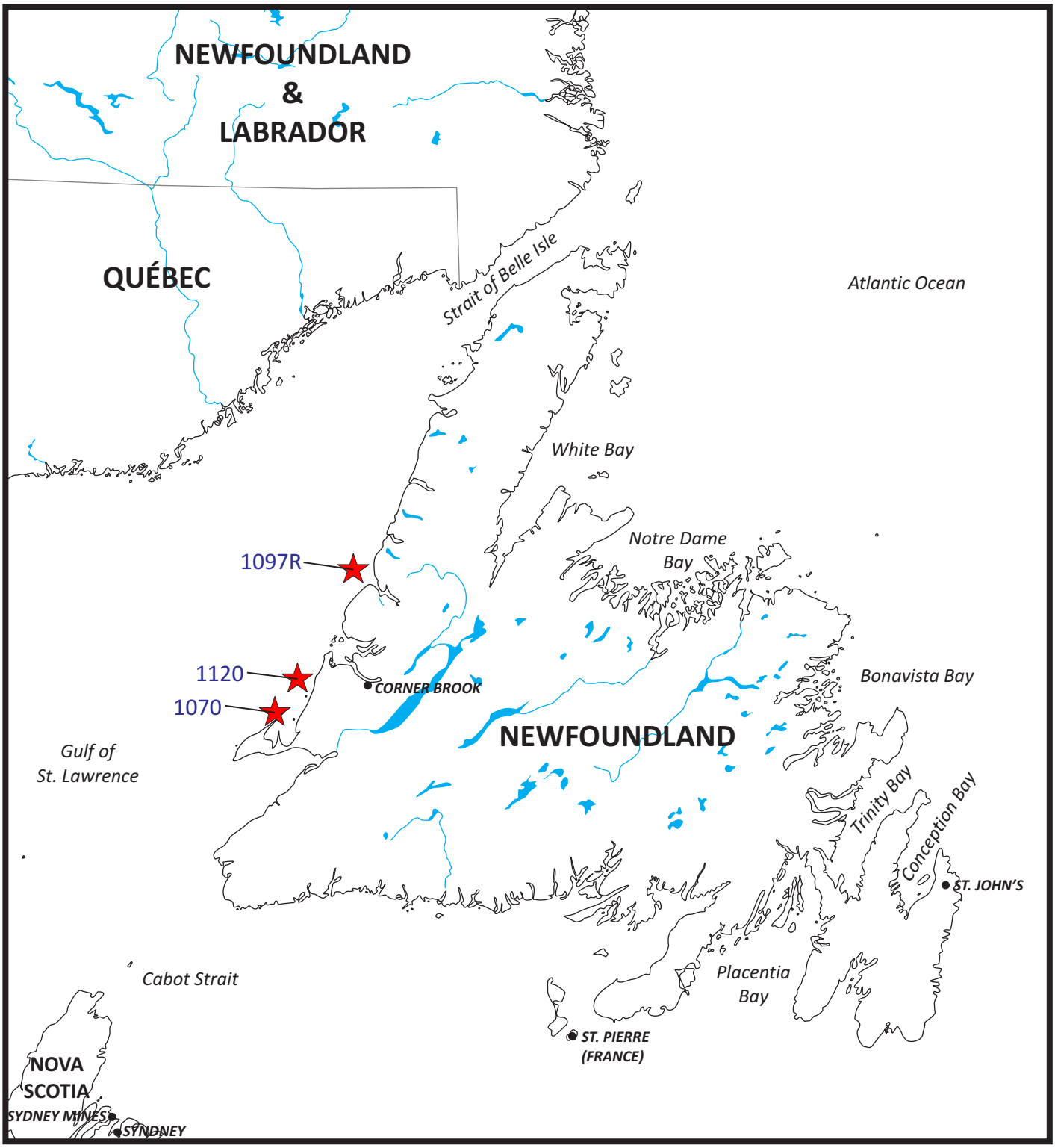
It has been a pleasure to perform this evaluation for you, and we trust it is sufficient to meet your current requirements. Should you have any questions, please contact our office.

Yours truly,

Original signed by: "Robin G. Bertram"

Robin G. Bertram, P. Eng.
Associate Partner
Deloitte & Touche LLP

/ct



★ Evaluated Property

Kilometers
0 100
0 100
Miles

ajm **Deloitte.**

Shoal Point Energy Ltd.
Property Locations
Effective March 31, 2012

By : laj		Date : 2012/05/01
Project : sho loc		

ajm Deloitte.

Independent petroleum consultants consent

The undersigned firm of Independent Qualified Reserves Evaluators and Auditors of Calgary, Alberta, Canada has prepared an independent evaluation of resources and value of certain oil and gas assets of the interests of Shoal Point Energy Ltd. It hereby gives consent to the use of its name and to the said estimates. The effective date of this evaluation is March 31, 2012.

This report has been prepared for the exclusive use of Shoal Point Energy Ltd. and no part thereof shall be reproduced, distributed or made available to any other person, company, regulatory body or organization without the complete context of this report and the knowledge and consent of AJM Deloitte.

In the course of the evaluation, Shoal Point Energy Ltd. provided AJM Deloitte personnel with basic information which included land, well and accounting (product prices and operating costs) information; reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from AJM Deloitte non confidential files. The extent and character of ownership and accuracy of all factual data supplied for the independent evaluation, from all sources, has been accepted.

A "Representation Letter" dated April 16, 2012 and signed by both the President and the Chief Financial Officer was received from Shoal Point Energy Ltd. prior to the finalization of this report. This letter specifically addressed the accuracy, completeness and materiality of all the data and information that was supplied to us during the course of our evaluation of Shoal Point Energy Ltd.'s resources and net present values. This letter is included within.

A field inspection and environmental/safety assessment of the properties was beyond the scope of the engagement of AJM Deloitte and none was carried out. The "Representation Letter" received from Shoal Point Energy Ltd. provided assurance that no additional information necessary for the completion of our assignment would have been obtained by a field inspection.

The accuracy of any resource and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resource and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision either upward or downward. AJM Deloitte reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

Revenue projections presented in this report are based in part on forecasts of market prices, current exchange rates, inflation, market demand and government policy which are subject to uncertainties and may in future differ materially from the forecasts herein. Present values of future net revenues documented in this report do not necessarily represent the fair market value of the reserves evaluated herein.

PERMIT TO PRACTICE

Deloitte & Touche LLP
Permit Number: P-11444

The Association of Professional Engineers,
Geologists and Geophysicists of Alberta

ajm Deloitte.

Certificate of qualification

I, R. G. Bertram, a Professional Engineer, of the 6th Floor, 425 – 1st Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am an associate partner of Deloitte & Touche LLP ("AJM Deloitte"), which did prepare an evaluation of certain oil and gas assets of the interests of Shoal Point Energy Ltd. The effective date of this evaluation is March 31, 2012.

2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Shoal Point Energy Ltd.

3. I attended the University of Alberta and graduated with a Bachelor of Science Degree in Petroleum Engineering in 1985; that I am a Registered Professional Engineer in the Province of Alberta; and I have in excess of twenty six years of engineering experience.

4. I am a Qualified Reserves Auditor as defined in the Canadian Oil and Gas Evaluation Handbook, Volume 1, Section 3.2.

5. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "R. G. Bertram"
R. G. Bertram, P. Eng.

April 30, 2012
Date

ajm Deloitte.

Certificate of qualification

I, L. D. Boyd, a Registered Professional Geologist, of the 6th Floor, 425 – 1st Street S.W., Calgary, Alberta, Canada hereby certify that:

1. I am an employee of Deloitte & Touche LLP ("AJM Deloitte"), which did prepare an evaluation of certain oil and gas assets of the interests of Shoal Point Energy Ltd. The effective date of this evaluation is March 31, 2012.

2. I do not have, nor do I expect to receive any direct or indirect interest in the properties evaluated in this report or in the securities of Shoal Point Energy Ltd.

3. I attended the University of Calgary and graduated with a Bachelor of Science Degree in Geology in 1976; that I am a Registered Professional Geologist in the Province of Alberta; and I have in excess of thirty five years of geological experience.

4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from the files of the interest owners of the properties and the appropriate provincial regulatory authorities.

Original signed by: "L. D. Boyd"
L. D. Boyd, P. Geol.

April 30, 2012
Date

SHOAL POINT energy

April 16, 2012

AJM Deloitte
East Tower, Fifth Avenue Place
6th Floor, 425 – 1st Street S.W.
Calgary, Alberta
T2P 3L8

Re: Standard Representation Letter
Resource Evaluation

Regarding the evaluation of our Company's oil and gas resources effective Mach 31, 2012 (the "effective date"), we herein confirm to the best of our knowledge and belief as of the effective date of the resource evaluation, the following representations and information made to you during the course and conduct of the evaluation.

1. We (the "Client") have made available to you (the "Evaluator") certain records, information and data relating to the evaluated properties that we confirm is, with the exception of immaterial items, complete and accurate as of the effective date of the resource evaluation including the following:

   a. asset ownership;
   b. all technical information including geological, engineering and production and test data;
   c. definition and delineation of the area and /or properties to be evaluated;
   d. determination and definition of geological formations and the resources thereof to be reviewed.

2. We confirm that our Company has satisfactory title to all of the assets, whether tangible, intangible or otherwise, for which accurate and current ownership information has been provided.

3. With the possible exception of items of an immaterial nature, we confirm as of the effective date of the evaluation that:

   a. This letter provides assurance that no additional information necessary for the completion of your assignment would have been obtained by a field inspection.
   b. Except as disclosed to you, the producing trend and status of each evaluated well or entity in effect throughout the three month period preceding the effective date of the evaluation are consistent with those that existed for the same well or entity immediately prior to this period.
   c. Between the effective date of the report and the date of this letter, nothing has come to our attention that has materially affected or could materially affect the resources and the economic value of these resources that has not been disclosed to you.

Yours truly,

George S. Langdon
President

R. Brian Murray
Chief Financial Officer

Evaluation procedure

Definitions and methodology

Effective as of March 2012

Table of contents

Procedure

AJM Deloitte has prepared estimates of resources and reserves in accordance with the process published in The Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1, 2nd Edition. The reader is referred to the Handbook for a complete description of the particular process quoted as follows.

Resources or reserves evaluation

A "Resources or Reserves Evaluation" is the process whereby a qualified reserves evaluator estimates the quantities and values of oil and gas resources or reserves by interpreting and assessing all available pertinent data. The value of an oil and gas asset is a function of the ability or potential ability of that asset to generate future net revenue, and it is measured using a set of forward-looking assumptions regarding resources or reserves, production, prices, and costs. Evaluations of oil and gas assets, in particular reserves, include a discounted cash flow analysis of estimated future net revenue.

Reserves audit

A "Reserves Audit" is the process carried out by a qualified reserves auditor that results in a reasonable assurance, in the form of an opinion, that the reserves information has in all material respects been determined and presented according to the principles and definitions adopted by the Society of Petroleum Evaluation Engineers ("SPEE") (Calgary Chapter), and Association of Professional Engineers and Geoscientists of Alberta ("APEGA") and are, therefore free of material mis-statement.

The reserves evaluations prepared by the Corporation have been audited, not for the purpose of verifying exactness, but the reserves information, company policies, procedures, and methods used in estimating the reserves will be examined in sufficient detail so that AJM Deloitte can express an opinion as to whether, in the aggregate, the reserves information presented by the Corporation are reasonable.

AJM Deloitte may require its own independent evaluation of the reserves information for a small number of properties, or for a large number of properties as tests for the reasonableness of the Corporation's evaluations. The tests to be applied to the Corporation's evaluations insofar as their methods and controls and the properties selected to be re-evaluated will be determined by AJM Deloitte, in its sole judgment, to arrive at an opinion as to the reasonableness of the Corporation's evaluations.

Reserves review

A "Reserves Review" is the process whereby a reserves auditor conducts a high-level assessment of reserves information to determine if it is plausible. The steps consist primarily of enquiry, analytical procedure, analysis, review of historical reserves performance, and discussion with the Corporation's reserves management staff.

"Plausible" means the reserves data appear to be worthy of belief based on the information obtained by the independent qualified reserves auditor in carrying out the aforementioned steps. Negative assurance can be given by the independent reserves auditor, but an opinion cannot. For example, "Nothing came to my attention that would indicate the reserves information has not been prepared and presented in accordance with principles and definitions adopted by the SPEE (Calgary Chapter), and APEGA (Practice Standard for the Evaluation of Oil and Gas Reserves for Public Disclosure).

Reviews do not require examination of the detailed document that supports the reserves information, unless this information does not appear to be plausible.

Resource and reserve definitions

The term "resources" encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, total resources are equivalent to Total Petroleum Initially-In-Place ("PIIP").

Total Petroleum Initially-In-Place ("PIIP") is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Discovered Petroleum Initially-In-Place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Petroleum Initially-In-Place includes Production, Reserves, and Contingent Resources; the remainder is unrecoverable.

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on development and production status. Refer to the full definitions on Reserves in Section 5.4 of COGEH.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Refer to COGEH and Figure 5-1.

Unrecoverable is that portion of Discovered and Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of Undiscovered Petroleum Initially-In-Place is referred to as Prospective Resources; the remainder as Unrecoverable.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Refer to COGEH and Figure 5-1.

Reserves, Contingent Resources, and Prospective Resources should not be combined without recognition of the significant differences in criteria associated with their classification. For example, the sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as Remaining Recoverable Resources. When resources categories are combined, it is important that each component of the summation also be provided, and it should be made clear whether and how the components in the summation were adjusted for risk.

Uncertainty ranges

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

Assessing commerciality

In order to assign recoverable resources of any category, a development plan consisting of one or more projects needs to be defined. In-place quantities for which a feasible project cannot be defined using established technology or technology under development are classified as unrecoverable. In this context "technology under development" refers to technology that has been developed and verified by testing as feasible for future commercial applications to the subject reservoir. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. In most cases recovery efficiency will be largely based on analogous projects.

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality". The chance of commerciality varies in different categories of recoverable resources as follows:

Reserves: To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

Contingent Resources: Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over

the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development". For contingent resources the chance of commerciality is equal to the chance of development.

Prospective Resources: Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery". Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components – the chance of discovery and the chance of development.

Economic status

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to sub-classify contingent resources by economic status.

Economic Contingent Resources are those contingent resources that are currently economically recoverable.

Sub-Economic Contingent Resources are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is "undetermined" (i.e., "contingent resources – economic status undetermined").

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e. specified economic conditions, which are generally accepted as being reasonable (refer to COGEH Volume 2, Section 5.8).

Reserve categories

Reserves are classified by AJM Deloitte in accordance with the following definitions published by COGEH and which meet the standards established by National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities and found in Appendix 1 to Companion Policy 51-101 CP, Part 2 Definition of Reserves.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and production status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories:

Developed Reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of certainty for reported reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest – level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Resource and reserve estimation

AJM Deloitte generally assigns reserves to properties via deterministic methods. Probabilistic estimation techniques are typically used where there is a low degree of certainty in the information available and is generally used in resource evaluations. This will be stated within the detailed property reports.

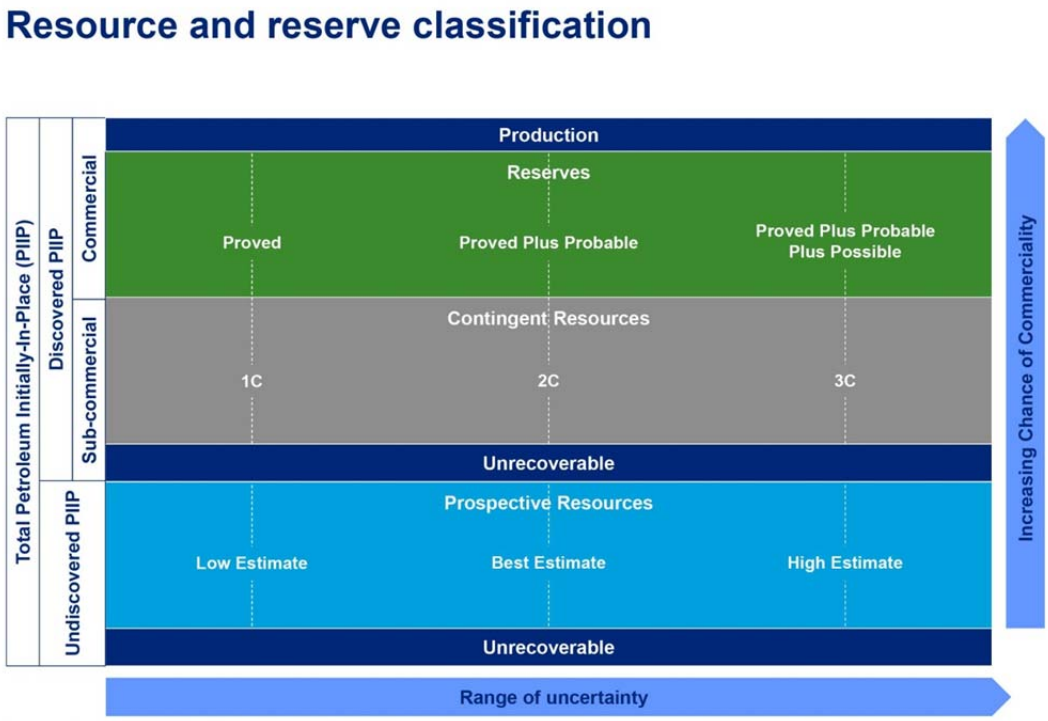


Image adapted from: SPE-PRMS, 2007

Deterministic

Reserves and resources were estimated either by i) volumetric, ii) decline curve analysis, iii) material balance techniques, or iv) performance predictions.

Volumetric reserves were estimated using the wellbore net pay and an assigned drainage area or, where sufficient data was available, the reservoir volumes calculated from isopach maps. Reservoir rock and fluid data were obtained from available core analysis, well logs, PVT data, gas analysis, government sources, and other published information either on the evaluated pool or from a similar reservoir in the immediate area. In mature (producing) reservoirs decline curve analysis and/or material balance was utilized in all applicable evaluations.

Statistical analysis

Whenever there is the need within an evaluation to assign reserves based on analogy or when volumetric reserves are being assigned, AJM Deloitte utilizes a variety of different tools in support of. When evaluating Western Canadian prospects, typically AJM Deloitte uses petroCUBE™.

The petroCUBE program is a web-based (www.petroCUBE.com) product co-developed by AJM Deloitte and geoLOGIC Systems Inc. petroCUBE provides geostatistical, technical, and financial information for conventional hydrocarbon plays throughout the Western Canadian Sedimentary Basin ("WCSB").

The information provided by petroCUBE is an unbiased independent perspective into the historical performance of the conventional hydrocarbon activity in the WCSB. The statistical information is presented by commodity type (gas, oil) with each commodity further analyzed by geographic area and play type.

Analysis output includes cumulative frequency resource distribution curves, chance of success tables, production performance profiles for each play type and area, unrisked and risked resources, and initial production rates on a per well zone basis, and full cycle economic and play parameters.

Cumulative frequency curves show how the volumes for a play are distributed. These calculations include the average volumes for a play (P_{50}), volumes for the best 10 percent of the wells (P_{10}), the minimum volumes developed by 90 percent of the wells (P_{90}).

Reserves assigned are compared to those volumes noted in the cumulative frequency curves for the corresponding area and play type. Typically an expected or proved plus probable reserve is a P_{50} volume.

Probabilistic

Because of the uncertainty inherent in reservoir parameters, probabilistic analysis, which is based on statistical techniques, provides a formulated approach by which to obtain a reasonable assessment of the petroleum initially in place (PIIP) and/or the recoverable resource. Probabilistic analysis involves generating a range of possible outcomes for each unknown parameter and their associated probability of occurrence. When probabilistic analysis is applied to resource estimation, it provides a range of possible PIIPs or recoverable resources.

In preparing a resource estimate, AJM Deloitte assesses the following volumetric parameters: areal extent, net pay thickness, porosity, hydrocarbon saturation, reservoir temperature, reservoir pressure, gas compressibility factor, recovery factor, and surface loss. A team of professional engineers and geologists experienced in probabilistic resource evaluation considered each of the parameters individually to estimate the most reasonable range of values. Working from existing data, the team discusses and agrees on the low (P_{90}) and high (P_{10}) values for each parameter. To help test the reasonableness of the proposed range, a minimum (P_{99}) and maximum (P_1) value are also extrapolated from the low and high values. After ranges have been established for each parameter, these independent distributions are used to determine a P_{90}, P_{50}, and P_{10} result which comprise AJM Deloitte's estimated range of PIIP or recoverable resource.

It is important to note that the process used to determine the final P_{10}, P_{90}, and P_{50} results involves multiplying the various volumetric parameters together. This yields results which require adjustments to maintain an appropriate probability of occurrence. For example, when calculating total reservoir volume (Area x Pay), the chance of getting a volume greater than the P_{10} Area x P_{10} Pay is less than 10 percent – the chance of getting the calculated result is only 3.5 percent ($p_{3.5}$). As you multiply additional P_{10} values, the probability of achieving the calculated value becomes less likely. Similarly, multiplying P_{90} parameters together will yield a result that has a probability greater than P_{90}. As such, when multiplying independent distributions together the results must be adjusted via interpolation to determine final P_{90} and P_{10} values.

The results appearing in this report represent interpolated P_{90} and P_{10} values. As defined by COGEH (and the Petroleum Resource Management System "PRMS"), the P_{50} estimate is the "best estimate" for reporting purposes.

Production forecasts

Production forecasts were based on historical trends or by comparison with other wells in the immediate area producing from similar reservoirs. Non-producing gas reserves were forecast to come on-stream within the first two years from the effective date under direct sales pricing and deliverability assumptions, if a tie-in point to an existing gathering system was in close proximity (approximately two miles). If the tie-in point was of a greater distance (and dependent on the reserve volume and risk) the reserves were forecast to come on-stream in years three or four from the effective date. If the reserves were located in a remote location and/or the reserve volume was of higher risk, the reserves were forecast to come on-stream beyond five years from the effective date. These on-stream dates were used when the company could not provide specific on-stream date information.

Land schedule and maps

The evaluated Corporation provided schedules of land ownership which included lessor and lessee royalty burdens. The land data was accepted as factual and no investigation of title by AJM Deloitte was made to verify the records.

Well maps included within this report represent all of the Corporation's interests that were evaluated in the specified area.

Geology

An initial review of each property is undertaken to establish the produced maturity of the reservoir being evaluated. Where extensive production history exists a ge ologic analysis is not conducted since the remaining hydrocarbons can be determined by productivity analysis.

For properties that are not of a mature production nature a geologic review is conducted. This work consists of:

- developing a regional understanding of the play,
- assessing reservoir parameters from the nearest analogous production,
- analysis of all relevant well data including logs, cores, and tests to measure net formation thickness (pay), porosity, and initial water saturation,
- auditing of client mapping or developing maps to meet AJM Deloitte's need to establish volumetric hydrocarbons-in-place.

Procedures specific to the project are discussed in the body of the report.

Royalties and taxes

General

All royalties and taxes, including the lessor and overriding royalties, are based on government regulations, negotiated leases or farmout agreements, that were in effect as of the evaluation effective date. If regulations change, the net after royalty recoverable reserve volumes may differ materially.

AJM Deloitte utilizes a variety of reserves and valuation products in determining the result sets.

Capital and operating considerations

Operating and capital costs were based on current costs escalated to the date the cost was incurred, and are in current year dollars. The economic runs provide the escalated dollar costs as found in the Pricing Table 1 in the Price and Market Demand section.

Reserves estimated to meet the standards of NI 51-101 for constant prices and costs (optimal), are based on unescalated operating and capital costs.

Capital costs were either provided by the Corporation (and reviewed by AJM Deloitte for reasonableness); or determined by AJM Deloitte taking into account well capability, facility requirement, and distance to markets. Facility expenditures for shut-in gas are forecast to occur prior to the well's first production.

Operating costs were determined from historical data on the property as provided by the evaluated Corporation. If this data was not available or incomplete, the costs were based on AJM Deloitte experience and historical database. Operating costs are defined into three types.

The first type, variable ($/Unit), covers the costs directly associated with the product production. Costs for processing, gathering and compression are based on raw gas volumes. Over the life of the project the costs are inflated in escalated runs to reflect the increase in costs over time. In a constant dollar review the costs remain flat over the project life.

The second type, fixed plant or battery ($/year), is again a fixed component over the project life and reflects any gas plant or battery operating costs allocated back to the evaluated group. The plant or battery can also be run as a separate group and subsequently consolidated at the property level.

The third type takes the remaining costs that are not associated with the first two and assigns them to the well based on a fixed and variable component. A split of 65 percent fixed and 35 percent variable assumes efficiencies of operation over time, i.e.: the well operator can reduce the number of monthly visits as the well matures, workovers may be delayed, well maintenance can also be reduced. The basic assumption is that the field operator will continue to find efficiencies to reduce the costs over time to maintain the overall $/Boe cost. Thus as the production drops over time the 35 percent variable cost will account for these efficiencies. If production is flat all the costs will also remain flat. Both the fixed and variable costs in this type are inflated in the escalated case and held constant in the constant dollar review. These costs also include property taxes, lease rentals, government fees, and administrative overhead.

In reserve evaluations conducted for purposes of NI 51-101, or, if an economic analysis was prepared for a resource evaluation, well abandonment and reclamation costs have been included and these costs were either provided by the Corporation (and reviewed by AJM Deloitte for reasonableness) or based on area averages (only the base abandonment costs were utilized and no consideration for groundwater protection, vent flow repair costs, or gas migration costs were considered). If there were multiple events to abandon the costs were increased by a 25 percent factor. Site reclamation costs were based on information provided by the Corporation or based on area averages. For undeveloped reserve estimates for undrilled locations, both abandonment and site reclamation costs are also included for the purpose of determining whether reserves should be attributed to that property in the first year in which the reserves are considered for attribution to the property.

Price and market demand forecasts

Base case forecast effective March 31, 2012

The attached price and market forecasts have been prepared by AJM Deloitte, based on information available from numerous government agencies, industry publications, oil refineries, natural gas marketers, and industry trends.

The prices are AJM Deloitte's best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

In preparing the price forecast AJM Deloitte considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The base forecast for both oil and gas is based on NYMEX futures in US dollars.

The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are AJM Deloitte's interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

AJM Deloitte
Canadian Domestic Price Forecast
Base Case Forecast Effective March 31, 2012

					Crude Oil Pricing							Natural Gas Liquids Pricing				Natural Gas Pricing									Sulphur
												Edmonton Par Prices													
		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	WTI at Cushing Oklahoma US$/bbl Real	WTI at Cushing Oklahoma US$/bbl Current	Edmonton City Gate C$/bbl Real	Edmonton City Gate C$/bbl Current	Med. Oil 29 Deg. API Cromer, Sk. C$/bbl Current	Bow River 25 Deg. API Hardisty C$/bbl Current	Heavy Oil 12 Deg. API Hardisty C$/bbl Current	Ethane C$/bbl Current	Propane C$/bbl Current	Butane C$/bbl Current	Pentanes + Condensate C$/bbl Current	Alberta Reference Average Price C$/mcf Current	Alberta AECO Average Price C$/mcf Real	Alberta AECO Average Price C$/mcf Current	Alberta System Plant Gate Sales C$/mcf Current	Alberta Direct Plant Gate Sales C$/mcf Current	B.C. Direct Stn. 2 Sales C$/mcf Current	Sask. Direct Plant Gate Sales C$/mcf Current	NYMEX US$/Mcf Real	NYMEX US$/Mcf Current	Alberta Plant Gate C$/lt Current
H	1997	1.6%	1.6%	0.722	$27.04	$20.60	$36.73	$27.98	$23.71	$21.26	$14.35	n/a	$19.41	$19.02	$30.85	$1.87	$2.24	$1.71	$1.78	$1.69	$1.98	$1.74	$3.40	$2.59	$11.50
i	1998	0.7%	0.7%	0.675	$18.58	$14.38	$25.94	$20.08	$16.94	$14.63	$9.43	n/a	$11.97	$12.92	$22.35	$1.94	$2.67	$2.07	$1.90	$1.95	$2.00	$2.13	$2.73	$2.11	($6.51)
s	1999	1.8%	1.8%	0.648	$24.75	$19.29	$35.16	$27.41	$21.72	$20.29	$17.62	$8.09	$13.21	$14.39	$20.94	$2.48	$3.53	$2.75	$2.22	$2.50	$2.64	$2.61	$2.69	$2.10	$6.93
t	2000	2.6%	2.6%	0.674	$38.08	$30.22	$55.88	$44.33	$39.89	$34.46	$28.57	$14.10	$32.59	$36.51	$46.30	$4.51	$7.08	$5.62	$4.84	$5.47	$4.73	$5.05	$5.44	$4.32	$13.59
o	2001	2.5%	2.5%	0.646	$14.28	$25.87	$21.62	$39.17	$31.54	$25.12	$18.07	$17.20	$30.62	$30.49	$43.03	$5.39	$2.99	$5.42	$5.42	$5.26	$6.34	$6.10	$2.17	$3.93	($14.50)
r	2002	2.3%	2.3%	0.637	$31.23	$26.11	$48.24	$40.33	$35.52	$31.89	$27.63	$11.21	$20.92	$27.78	$41.22	$3.88	$5.01	$4.19	$3.85	$4.03	$4.09	$4.08	$4.02	$3.36	$12.74
i	2003	2.8%	2.8%	0.716	$36.26	$31.01	$50.87	$43.51	$37.47	$32.96	$27.35	$18.43	$32.31	$36.03	$45.18	$6.12	$7.81	$6.68	$6.11	$6.51	$6.42	$6.67	$6.40	$5.48	$40.99
c	2004	1.8%	1.8%	0.770	$47.11	$41.45	$60.19	$52.96	$45.76	$38.01	$30.44	$19.04	$35.20	$44.07	$55.49	$6.31	$7.45	$6.55	$6.32	$6.38	$6.52	$6.84	$7.10	$6.25	$40.82
a	2005	2.2%	2.2%	0.826	$63.16	$56.61	$77.35	$69.33	$57.39	$45.68	$33.77	$23.80	$43.23	$51.91	$74.67	$8.31	$9.80	$8.78	$8.56	$8.61	$8.22	$8.51	$9.94	$8.91	$40.99
l	2006	2.0%	2.0%	0.882	$72.05	$66.06	$79.99	$73.34	$62.42	$52.04	$39.68	$19.81	$44.11	$58.16	$78.19	$6.56	$7.13	$6.54	$6.63	$6.35	$6.57	$7.11	$7.36	$6.75	$19.51
	2007	2.1%	2.1%	0.935	$77.36	$72.38	$82.39	$77.09	$65.18	$53.86	$39.75	$18.41	$49.77	$59.40	$81.67	$6.20	$6.88	$6.44	$6.31	$6.22	$6.40	$6.54	$7.45	$6.97	$38.32
	2008	2.4%	2.4%	0.943	$104.15	$99.58	$107.55	$102.83	$93.26	$83.97	$73.17	$22.61	$56.94	$83.56	$109.80	$7.88	$8.53	$8.15	$8.13	$7.92	$8.21	$8.19	$9.28	$8.88	$304.51
	2009	0.3%	0.3%	0.880	$63.08	$61.78	$67.60	$66.21	$62.77	$59.90	$54.49	$11.60	$34.56	$56.29	$69.59	$3.84	$4.04	$3.96	$3.94	$3.74	$4.16	$4.14	$3.99	$3.90	($4.97)
	2010	1.8%	1.8%	0.971	$80.84	$79.42	$79.18	$77.79	$73.48	$68.16	$60.59	$11.52	$45.13	$68.78	$84.00	$3.76	$4.07	$4.00	$4.07	$3.76	$4.00	$3.90	$4.46	$4.38	$57.81
	2011	2.9%	2.9%	1.012	$94.91	$94.91	$95.58	$95.58	$88.21	$78.50	$69.56	$10.30	$52.44	$87.06	$105.31	$3.46	$3.63	$3.63	$3.84	$3.42	$3.34	$3.33	$3.99	$3.99	$79.49
2	3 Mths H	2.4%	2.4%	0.997	$103.00	$103.00	$93.63	$93.63	$88.16	$83.28	$72.33	$7.16	$50.38	$85.91	$106.92	$2.32	$2.16	$2.16	$2.42	$1.97	$2.69	$2.07	$2.47	$2.47	$80.00
0	9 Mths F	0.0%	0.0%	1.000	$100.00	$100.00	$98.00	$98.00	$91.00	$77.00	$71.00	$10.65	$55.00	$85.00	$105.00	$2.05	$2.30	$2.30	$2.00	$2.10	$2.00	$2.25	$2.80	$2.80	$80.00
1																									
2	Avg.	n/a	n/a	0.999	$100.75	$100.75	$96.91	$96.91	$90.29	$78.57	$71.33	$9.78	$53.85	$85.23	$105.48	$2.12	$2.26	$2.26	$2.11	$2.07	$2.17	$2.21	$2.72	$2.72	$80.00
F	2012	0.0%	0.0%	1.000	$100.00	$100.00	$98.00	$98.00	$91.00	$77.00	$71.00	$6.00	$53.90	$83.30	$102.90	$2.05	$2.30	$2.30	$2.00	$2.10	$2.00	$2.25	$2.80	$2.80	$80.00
o	2013	2.0%	2.0%	1.000	$100.00	$102.00	$98.00	$100.00	$92.30	$79.00	$73.00	$8.85	$55.00	$85.00	$105.00	$3.00	$3.20	$3.25	$2.95	$3.05	$2.95	$3.20	$3.50	$3.55	$81.60
r	2014	2.0%	2.0%	1.000	$100.00	$104.05	$98.00	$102.00	$93.00	$80.00	$74.00	$10.65	$56.10	$86.70	$107.10	$3.60	$3.70	$3.85	$3.55	$3.65	$3.55	$3.80	$4.00	$4.15	$83.25
e	2015	2.0%	2.0%	1.000	$100.00	$106.10	$98.00	$104.00	$94.25	$82.00	$76.00	$11.85	$57.20	$88.40	$109.20	$4.00	$4.00	$4.25	$3.95	$4.05	$3.95	$4.20	$4.30	$4.55	$84.90
c	2016	2.0%	2.0%	1.000	$100.00	$108.25	$98.00	$106.10	$95.60	$84.10	$78.10	$13.05	$58.35	$90.20	$111.40	$4.40	$4.30	$4.65	$4.35	$4.45	$4.35	$4.60	$4.60	$5.00	$86.60
a	2017	2.0%	2.0%	1.000	$100.00	$110.40	$98.00	$108.20	$96.95	$86.20	$80.20	$14.40	$59.50	$91.95	$113.60	$4.85	$4.60	$5.10	$4.80	$4.90	$4.80	$5.05	$4.90	$5.40	$88.35
s	2018	2.0%	2.0%	1.000	$100.00	$112.60	$98.00	$110.35	$98.35	$88.35	$82.35	$16.05	$60.70	$93.80	$115.85	$5.40	$5.00	$5.65	$5.35	$5.45	$5.35	$5.60	$5.30	$5.95	$90.10
t	2019	2.0%	2.0%	1.000	$100.00	$114.85	$98.00	$112.55	$99.05	$90.55	$84.55	$17.40	$61.90	$95.65	$118.20	$5.85	$5.30	$6.10	$5.80	$5.90	$5.80	$6.05	$5.60	$6.45	$91.90
	2020	2.0%	2.0%	1.000	$100.00	$117.15	$98.00	$114.80	$99.80	$92.80	$86.80	$19.20	$63.15	$97.60	$120.55	$6.45	$5.70	$6.70	$6.40	$6.50	$6.40	$6.65	$6.00	$7.05	$93.75
	2021	2.0%	2.0%	1.000	$100.00	$119.50	$98.00	$117.10	$102.10	$95.10	$89.10	$21.30	$64.40	$99.55	$122.95	$7.15	$6.20	$7.40	$7.10	$7.20	$7.10	$7.35	$6.50	$7.75	$95.65
	2022	2.0%	2.0%	1.000	$100.00	$121.90	$98.00	$119.45	$104.45	$97.45	$91.45	$21.75	$65.70	$101.55	$125.40	$7.30	$6.20	$7.55	$7.25	$7.35	$7.25	$7.50	$6.50	$7.90	$97.55
	2023	2.0%	2.0%	1.000	$100.00	$124.35	$98.00	$121.85	$106.85	$99.85	$93.85	$22.20	$67.00	$103.55	$127.95	$7.45	$6.20	$7.70	$7.40	$7.50	$7.40	$7.65	$6.50	$8.10	$99.50
	2024	2.0%	2.0%	1.000	$100.00	$126.80	$98.00	$124.30	$109.30	$102.30	$96.30	$22.65	$68.35	$105.65	$130.50	$7.60	$6.20	$7.85	$7.55	$7.65	$7.55	$7.80	$6.50	$8.25	$101.50
	2025	2.0%	2.0%	1.000	$100.00	$129.35	$98.00	$126.75	$111.75	$104.75	$98.75	$23.10	$69.70	$107.75	$133.10	$7.75	$6.20	$8.00	$7.70	$7.80	$7.70	$7.95	$6.50	$8.40	$103.55
	2026	2.0%	2.0%	1.000	$100.00	$131.95	$98.00	$129.30	$114.30	$107.30	$101.30	$23.70	$71.10	$109.90	$135.75	$7.95	$6.20	$8.20	$7.90	$8.00	$7.90	$8.15	$6.50	$8.60	$105.60
	2027	2.0%	2.0%	1.000	$100.00	$134.60	$98.00	$131.90	$116.90	$109.90	$103.90	$24.15	$72.55	$112.10	$138.50	$8.10	$6.20	$8.35	$8.05	$8.15	$8.05	$8.30	$6.50	$8.75	$107.70
	2028	2.0%	2.0%	1.000	$100.00	$137.30	$98.00	$134.55	$119.55	$112.55	$106.55	$24.60	$74.00	$114.35	$141.30	$8.25	$6.20	$8.50	$8.20	$8.30	$8.20	$8.45	$6.50	$8.90	$109.85
	2029	2.0%	2.0%	1.000	$100.00	$140.00	$98.00	$137.20	$122.20	$115.20	$109.20	$25.20	$75.45	$116.60	$144.05	$8.45	$6.20	$8.70	$8.40	$8.50	$8.40	$8.65	$6.50	$9.10	$112.05
	2030	2.0%	2.0%	1.000	$100.00	$142.80	$98.00	$139.95	$124.95	$117.95	$111.95	$25.65	$76.95	$118.95	$146.95	$8.60	$6.20	$8.85	$8.55	$8.65	$8.55	$8.80	$6.50	$9.30	$114.30
	2031	2.0%	2.0%	1.000	$100.00	$145.70	$98.00	$142.75	$127.75	$120.75	$114.75	$26.25	$78.50	$121.35	$149.90	$8.80	$6.20	$9.05	$8.75	$8.85	$8.75	$9.00	$6.50	$9.45	$116.60
	2032+	2.0%	2.0%	1.000	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%

Notes:
- All prices are in Canadian dollars except WTI and NYMEX gas which are in U.S. dollars.
- Edmonton city gate prices based on light sweet crude posted at major Canadian refineries. (40 Deg. API < 0.5% Sulphur)
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- System gas prices includes TCGSL, Progas, Pan Alberta and Alliance.
- Real dollars listed include future growth in prices with no escalation considered.
- Alberta gas prices, except AECO, include an Average cost of service to the plant gate.

Glossary of terms

AJM Deloitte subscribes to the Glossary of Terms as defined by the Canadian Oil and Gas Evaluation Handbook, Volume 2.

Property index

1. West Coast Newfoundland

Shoal Point Energy Ltd.

West Coast Newfoundland

Effective date: March 31, 2012

Prepared by:
R. G. Bertram, P. Eng.
L. D. Boyd, P. Geol.

Shoal Point Energy Ltd.
West Coast Newfoundland
Exploration Licenses 1070, 1120, and 1097R

Introduction

Shoal Point Energy Ltd. ("Shoal Point") has requested Deloitte & Touche LLP ("AJM Deloitte") to review and consolidate the results of prior resource reports prepared for blocks EL 1070, consolidated block EL 1097R (formerly: EL 1097, EL 1098, EL1103, EL 1104) and EL 1120 into a single resource report as Shoal Point has accumulated working interests in EL 1070 and 1097R and will have a working interest in EL 1120 after executing on a farm out agreement with Ptarmigan Energy Inc.

The Exploration Licences 1070, 1097R, and 1120 are located offshore on the west coast of Newfoundland, approximately 40 to 50 kilometres west of the town of Corner Brook and encompass the offshore area surrounding the Port au Port Peninsula and Bay north towards the coastal town of Bellburns. The acreage captured by the licences is as follows: EL 1070 = 103,040 hectares; EL 1097R = 202,838 hectares; EL 1120 = 140,210 hectares for a total of 446,088 hectares (1,102,308 acres).

The exploration licence EL 1070 was purchased in January of 2002 by Canadian Imperial Venture Corp. and covers a total area of approximately 103,040 hectares (254,509 acres). Shoal Point earned a 45.5 percent interest in the eastern portion of the licence by drilling the 2K-39 well in 2008. Pursuant to earning, Shoal Point formed an agreement with partners in the licence, to trade deep rights for an increased percentage of shallow rights. As a result, Shoal Point became operator of the shallow rights (Late Cambrian to Ordovician age sediments); their partner at that time was Canadian Imperial Venture Corp. ("CIVC"). During the past year, Shoal Point purchased Canadian Imperial Venture Corp.'s interest in the Green Point shale. As of September 25, 2011, Shoal Point has increased their working interest to 100 percent in Exploration licence 1070. Shoal Point has satisfied the "Period 1" term licence requirements by drilling and sampling the sediments within the 2K-39 wellbore. The offshore block of land is now subject to "Period 2" term of the licence requirements, to prove the existence of an accumulation of hydrocarbons that has the potential for sustained production. Shoal Point continues to advance the Green Point shale prospect by planning and drilling the 3K-39 well (see Development plans for discussion).

NWest Energy received approval from the Canada-Newfoundland and Labrador Offshore Petroleum Board in November 2011 to consolidate the company's four offshore Exploration licences 1097, 1098, 1103, and 1104 into the current Exploration Licence 1097R. The terms of the consolidation required NWest to surrender 456,711 hectares (1,128,557 acres) from the four exploration licences and retain

202,838 hectares (501,233 acres) in the consolidated EL 1097R. Period 1 of EL 1097R was to expire on January 15, 2012 unless NWest surrendered 50 percent of the contiguous lands with a payment of a refundable deposit of $250,000 or keep all of the contiguous 1097R acreage with a larger refundable drilling deposit of $1,000,000 which would place EL 1097R into Period 2. Period 2 expires on January 15, 2015 and in order to validate all sections of the Licence NWest must drill, complete, and adequately test a geological target of NWest's choice during the Period 2 transition. Subsequent to the successful consolidation of EL 1097R, NWest entered into an agreement with Shoal Point Energy Ltd. where NWest Energy Corp. and its subsidiary NWest Oil & Gas Inc. has transferred to Shoal Point 100 percent working interest in the exploration licence EL1097R. Shoal Point has posted a drilling deposit and has extended Period 1 to January 15, 2013; the earning well is planned to spud in the first quarter of 2013 (see section: Development Plans for further details).

The authorized representative for exploration licence EL 1120 is currently Ptarmigan Energy at 100 percent working interest. The licence is still in Period 1 and needs to be validated by a well. Ptarmigan Energy Inc. and Shoal Point Energy Ltd. have entered into a farm out agreement where Shoal Point will drill a test well in the fourth quarter of 2012. The well will validate the license and earn the shallow rights (Cow Head Group) in a portion of the licence about 27,183 ha (67,285 acres) that is immediately adjacent to the coast line and accessible to drill from onshore. After drilling and testing the well Shoal Point will have earned an 80 percent working interest in the farm out lands (see attached map of farm out acreage and see section: Development Plans for further details).

Resource categorization

Refer to the Evaluation procedure for comprehensive definitions of resources and reserves. For the Green Point shale within the production license, all resources-in-place have been considered "Undiscovered" until the results of the drilling and testing of 3K-39 well are complete and that sustained oil flow from the Green Point Shale is proven by current testing operations. Estimated recoverable resources are therefore defined as Prospective Resources.

Results and recommendations

The results of the stochastic analysis for each reservoir are included in the tables below. The total volumes are an arithmetic sum, which statistical principles indicate may be misleading as to the low and high estimate volumes that may actually be recovered. The sum of the best estimates is generally considered to be an approximation of overall best estimate. However, the sum of the low estimate is likely to be lower than the expected low estimate, and the sum of the high estimate is likely to be higher than the expected high estimate.

Summary of results

Summary of resources on Shoal Point lands[1]

Resource class			Gross			Working interest		
			Low [4]	Best[5]	High [6]	Low [4]	Best[5]	High [6]
			MMstb	MMstb	MMstb	MMstb	MMstb	MMstb
		Cumulative production[1][2]	0	0	0	0	0	0
		Remaining reserves[1][2]	0	0	0	0	0	0
		Surface loss/shrinkage	0	0	0	0	0	0
		Total commercial	0	0	0	0	0	0
		Contingent resources[2]	0	0	0	0	0	0
		Unrecoverable[3]	0	0	0	0	0	0
		Total sub-commercial	0	0	0	0	0	0
	Total discovered PIIP		0	0	0	0	0	0
		Prospective resources[2]	475	969	2,172	475	969	2,172
		Unrecoverable[3]	10,745	21,491	47,197	10,745	21,941	47,197
	Total undiscovered PIIP		11,220	22,460	49,369	11,220	22,460	49,369
Total PIIP			**11,220**	**22,460**	**49,369**	**11,220**	**22,460**	**49,369**

Notes:
(1) Effective March 31, 2012.
(2) Sales gas and NGL volumes combined as appropriate.
(3) Unrecoverable includes surface loss/shrinkage on contingent and prospective volumes.
(4) Low case reflects 1P reserves.
(5) Expected case reflects 2P reserves.
(6) High case reflects 3P reserves.

Additional details regarding the stochastic analysis are included within the Tables section of the report. Within these tables, the two unconventional shale zones were summed together using a Monte Carlo analysis, as were the four conventional Miocene structures.

Cautionary statements

The estimate of remaining recoverable resources (un-risked) includes prospective resources that have not been adjusted for risk based on the chance of discovery or chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development. Actual recovery is likely to be less and may be substantially less or zero.

Geology

The stratigraphy, the distribution of rock types, and geological structures in Newfoundland are the result of a complex history of plate tectonic activity. Newfoundland has been geologically subdivided into five techno-stratigraphic zones. The western zone is known as the Humber (Humber Arm Super group), which includes the west coast of Newfoundland from the Northern Peninsula through to the Port au Port Peninsula. The Humber zone is the northeastern extension of the Appalachian fold belt, which is a large tectonic system that extends along the eastern edge of North America. Presently many oil and gas companies are developing hydrocarbons in various shale basins along the Appalachian thrust belt (Barnett, Fayetteville, and the Utica).

The presence of numerous oil seeps along the west coast of Newfoundland particularly in the Port au Port Peninsula area and Parson's Pond have been known since the early 19th Century and several wells drilled in the early 20th Century have recovered small quantities of oil (reports of 10 to 20 barrels per day of light gravity crude 32° to 51°API). Biomarker distributions indicate that the shales of the Green Point Formation are the source of the oils obtained from seeps and wells (Fowler et al, 1995). The Green Point shale is the proven source rock for the Anticosti Basin onshore and is present in the Humber Arm allochthonous sedimentary rocks.

Industry has been able to use offshore and onshore seismic surveys to interpret the areal extent of a thrust package - "triangle zone" – of the Humber Arm Allochthon over an area of approximately 1,600 Km^2 extending from south to north offshore adjacent to the west coast shoreline. Surface geological mapping confirms the presence of the Allochthon and Green Point shale onshore in Port Au Port Peninsula area. Seismic lines crossing Shoal Point's land and outcrop information show the presence of the Allochthon onshore and offshore from Port Au Port Peninsula north towards the town of Bellburns along the western coast (see attached map appendix A). The presence of the Allochthon within Shoal Point's licences proves the acreage as prospective for oil in the shallow shales of the Cow Head Group (Green Point Formation).

The purpose of this report is to provide a stochastic analysis of the potential in place oil resource that may be present on the licences: EL 1070, EL 1120 and EL 1097R acreage. To estimate the potential extent of the Humber Arm Allochthon and the Green Point shale (illustrated in the attached map, see appendix A) AJM Deloitte relied on seismic data provided by the client, specifically interpreted seismic maps over EL 1070 and 1097R. On seismic the boundaries of the Triangle zone of the Humber Arm Allochthon are defined by the intersection of the Tea Cove thrust and the Round Head Thrust at the apex of the triangle and at the base by the intersection of each fault with the underlying platform sediments. AJM Deloitte assumed that the resource potential of the Green Point within a gross Allochthon thickness below 1,000

metres may not be material to the total resource potential within the lease. The Allochthon thickness below 1,000 metres is considered too thin to have significant resource potential within the Green Point shale and has been excluded from the estimate of the Green Point Resource area. The acreage within the map area shaded brown provided an estimate of the maximum area (P_1) possible where the Green Point shale might be encountered.

Gross thickness of the Green Point was estimated from the seismic by assuming an average travel time velocity of 2,000 metres per second within the Allochthon sediments and that time thickness was reconciled to the estimated thickness encountered in the well M-16 to result in a (P_1) maximum thickness of approximately 3,000 metres. Net thickness was determined by applying a net to gross ratio to the gross thickness. The values for the net to gross ratios were based on the following assumptions: the Green Point shale sediments are only a portion of the Allochthon triangle and seismic is unable to resolve for the actual thickness of shale. The net thickness of the Green Point shale within the Triangle zone is conjecture and although the entire mapped area of the triangle has been considered at this point as there is no well onshore that currently penetrates the thicker portion of the Allochthon.

The estimates of porosity ranges and net to gross are consistent with interpretations derived from consultant's (proprietary report by Nutech) analysis of the M-16 well drilled on Long Point. The remaining estimates of reservoir parameters have relied on experience with shale oil and gas reservoirs in North America.

Analogous plays

Currently there is no commercial production from the unconventional late Cambrian Green Point shale of West Newfoundland in order to draw nearby analogs from. The evaluation of the unconventional shale has relied upon experience gained in evaluation of the unconventional Green Point shale in the Port au Port area of Western Newfoundland, Canada, as well as other shale oil and gas reservoirs in western Canada.

Geological risk factors

The geological risk factors are summarized within the Tables Section of the report. A total of six criteria are considered in determining the overall geological risk.

- Source rock – is there thermally mature hydrocarbon source rock present in adequate thickness, extent and organic richness,
- Charge – is the source rock capable of generating hydrocarbon,

- Migration – are there sufficient migration pathways such as faults, fractures and carrier beds to the reservoir,
- Reservoir rock – does the reservoir have favourable parameters such as thickness, pore space and the ability to allow fluid flow,
- Trap / Closure – does closure of the reservoir exist in terms of adequate areal extent and vertical relief,
- Seal / Containment – are there effective sealing rocks present to ensure that containment has occurred.

A factor ranging from zero to one is assigned to each criterion. The geological chance of success is the product of all of the factors. For the unconventional targets, the geological chance of success is 18 percent, whereas the conventional targets geological chance of success is estimated to be 20 percent.

Technical assessment

Probabilistic analysis

AJM Deloitte has prepared a statistical estimate of the expected oil-in-place resource based on a volumetric analysis of the Green Point shale. Because of the uncertainty inherent in reservoir parameters, probabilistic analysis, which is based on statistical techniques, provides a formulated approach by which to obtain a reasonable assessment of the petroleum initially-in-place ("PIIP").

Due to the uncertainty related to undiscovered accumulations, the most appropriate method of estimating the prospective resources is to prepare a stochastic analysis of the target reservoir. The probabilistic analysis involves generating a range of possible outcomes for each unknown parameter along with its associated probability of occurrence. When a probabilistic analysis is applied to resource estimation, it provides a range of resource estimates.

All of the ranges assume a lognormal distribution, and the P_{90} (low), P_{50} (best), and P_{10} (high) parameters are shown in the attached tables. During the preparation of the distributions, the P_{99} (minimum) and P_1 (maximum) outcomes are also reviewed to ensure an appropriate distribution. The determination of the P_{90}, P_{50}, and P_{10} oil-in-place estimates included a volumetric calculation to estimate the original oil-in-place in the reservoir. The products of these volumetric calculations were plotted on a probability scale so that the correct P_{90} and P_{10} oil-in-place volumes could be interpolated.

In preparing a resource estimate for the Green Point shale, AJM Deloitte assessed the following volumetric parameters: areal extent, pay thickness, porosity, hydrocarbon saturation, shrinkage, and recovery factor. The determination of probabilistic distributions of reservoir parameters relied on seismic mapping and other data supplied by Shoal Point which consisted of PowerPoint presentations, published papers and personal communications. AJM Deloitte considered a wide distribution range for the low (P_{90}) to high (P_{10}) scope when estimating each of the geological parameters because of the uncertainty at this stage of exploration.

Area

The estimate of the range between the P_{90} productive area and P_{10} productive area is wide because of the uncertainty of the extent and distribution of reservoir quality and oil saturation in the allochthonous sediments. The areal extent of the unconventional shale was estimated from regional mapping; outcrop information and a review of various reports detailing the geology of the basin (see reference section).

Gross thickness

The gross thickness of the Humber Arm Allochthon was determined from seismic mapping of the thrust package that contains the Green Point shale and onshore outcrop information supplied by the client. The gross thickness of the Allochthon ranges from a minimum (P_{99}) of approximately eight metres to a maximum (P_1) of 890 metres.

Net to gross ratio

Net to gross ratio to determine net thickness of Green Point shale was contemplated as an estimated percentage of the total Allochthon triangle as seismic is unable to resolve the net thickness of the shale.

Porosity, hydrocarbon saturations, formation volume factors

The reservoir parameters assigned to the unconventional shales are consistent with parameters assigned to other typical shale resource plays. As shale oil zones have historically not been evaluated in detail, specific values related to the porosity, saturation and formation volume factor are subject to a wide distribution.

The porosity range was estimated by considering a P_{99} of approximately 2.5 percent, and a P_1 of approximately 20 percent.

Hydrocarbon saturation uncertainty was considered by assigning a wide range of possible outcomes, from a P_{99} of approximately 15 percent and a P_1 of 70 percent.

Shrinkage (Formation Volume Factor) is also set at a wide range, considering the possibility of over pressured reservoirs.

Recovery factor

The recovery assigned to the unconventional shales ranges from three percent for the P_{90} to six percent for the $P_{10.}$ This range allows for recoveries as low as two percent (P_{99}) and as high as eight percent (P_1). Until there is better understanding of the production characteristics of the Green Point shale, the assignment of conservative recovery factors is reasonable for the targets considered for future development.

Development plans

Exploration License 1070

The Exploration well 3K-39 commenced drilling operations in the first quarter of 2011. The initial drilling of the well was finished in August 2011, at which time drilling was suspended; pending approval of the testing program. The testing program was completed at Shoal Point 3K39z on May 24, 2012 and currently the crew is swabbing the well while waiting for enhanced completion operations approval.

The following table summarizes the costs incurred to date and anticipated completion costs to stimulate the reservoir and recover hydrocarbons:

	Acquisition	Exploration	Total
January 31, 2012	$4,677,552	$21,659,236	$26,336,788
February 1,2012 to April 30, 2012	$200,000	$6,788,940	$6,988,940
Total	$4,877,552	$28,448,176	$33,325,728
Total Costs to April 30,2012			$33,325,728
Anticipated fracture stimulation			$1,750,000

After a successful fracture stimulation program and hydrocarbons are recovered, the Company plans to make application to the regulatory authority, by the end of 2012, for a Significant Discovery License – lands included in this License will be preserved in perpetuity for production. Parallel to this process, a Development Plan will be filed which, once approved, will allow the Company to proceed with future drilling of appraisal and development wells on the SDL. The first appraisal well is projected for early 2014 on this SDL, and is expected to cost $6 million.

The following development plans for Exploration Licences 1120 and 1097R are contingent upon successfully obtaining additional subsequent financing:

Exploration License 1120

An earning well is planned for the final quarter of 2012 on EL 1120. Shoal Point will operate a well at a site in Littleport village, on the coast along the Gulf of St. Lawrence approximately five kilometers south of the Bay of Islands. This well will be programmed to a depth of 2,500 metres and will be deviated from onshore to test the offshore license. The prospective Green Point Formation is expected to be encountered at a depth between 500 -1,000 metres. This well is expected to cost approximately $8

million. With this well, Shoal Point will earn an 80 percent working interest in approximately 67,000 acres along the coast on EL 1120.

Exploration License 1097R

An earning well is planned for the first quarter of 2013, and will follow the Littleport well once the rig has been release from that site. Shoal Point will operate a well at a site yet to be determined, but at a point along the coast of good access, low population and proximity to the shoreline. This well will be programmed to a depth of 2,500 metres and will be deviated from onshore to test the offshore license. The well will be spudded in the prospective Green Point Formation, and is expected to remain in this formation until total depth. The well is expected to cost approximately $8 million, and with it, Shoal Point Energy will fulfil a commitment to earn a 100 percent working interest in approximately 500,000 acres in EL 1097R.

West Newfoundland onshore land sale

A Call for Bids may be issued in 2012 for onshore petroleum rights in western Newfoundland. Depending on the forthcoming results of its current testing on EL 1070, and to some extent market conditions, the Company may decide to participate in this land sale. To that effect, it may attempt to identify a joint venture partner, or chose to commit its own funds to deposits associated with bid submission, up to $5 million, to participate in this sale.

Development risk factors

The chances of geological success are discussed within the Geology section of the report. The chances of development for the estimated prospective resources are subject to a number of factors, including: the overall project economics, the employed recovery technology or technology under development, regulatory and environmental approval, the availability of markets and production facilities, and political risk to the development.

Prior to committing to any defined development, additional drilling, sampling and testing will be required to further quantify the hydrocarbon potential in the permit.

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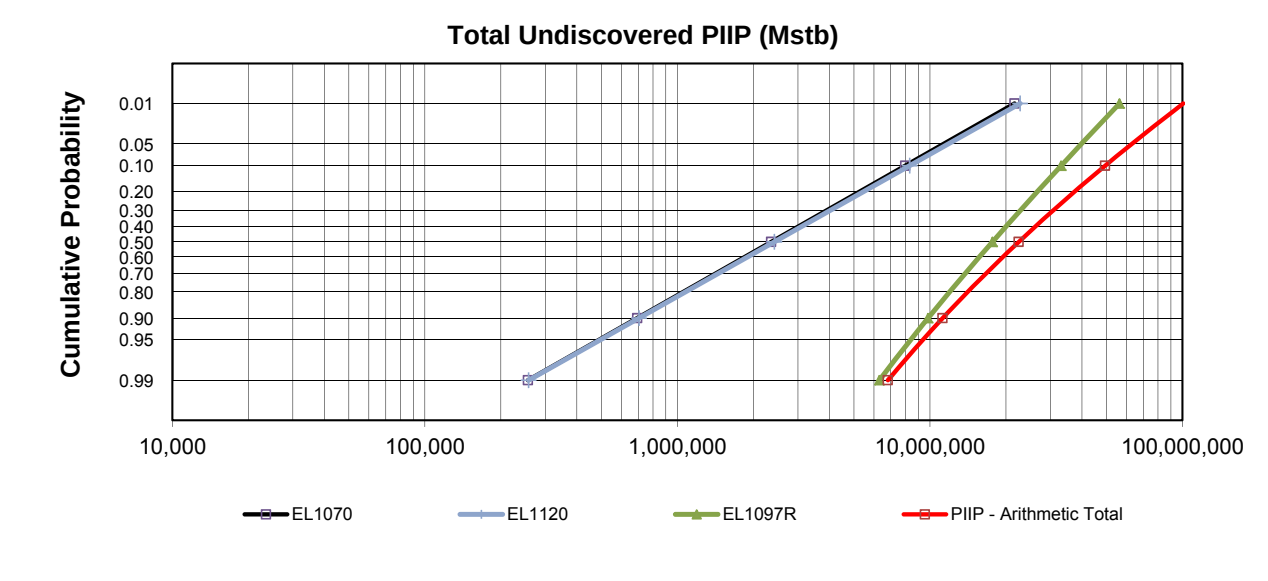
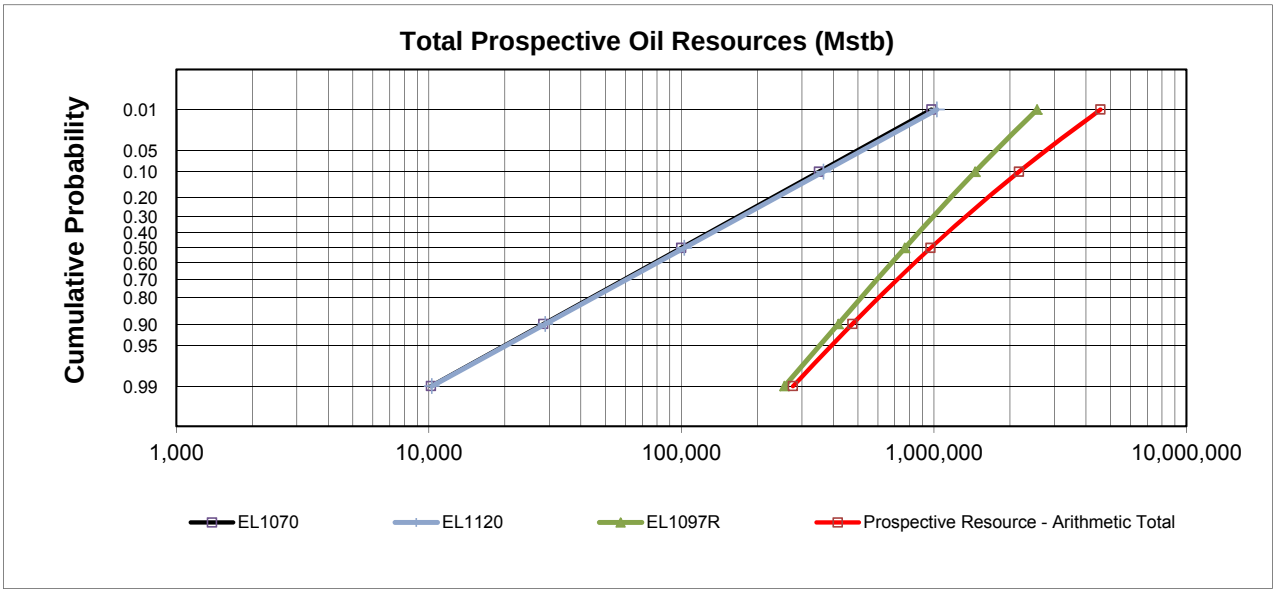
Company Evaluated: Shoal Point Energy
Appraisal For: Shoal Point Energy - West Coast Newfoundland
Permit / Block: EL1070, EL1120, EL1097R

			Low	Best	High
EL1070	Green Point Shale	Mstb	693,289	2,352,512	7,982,691
EL1120	Green Point Shale	Mstb	704,329	2,420,715	8,319,780
EL1097R	Green Point Shale	Mstb	9,822,002	17,687,031	33,066,136
Undiscovered PIIP		**Mstb**	**11,219,620**	**22,460,258**	**49,368,606**

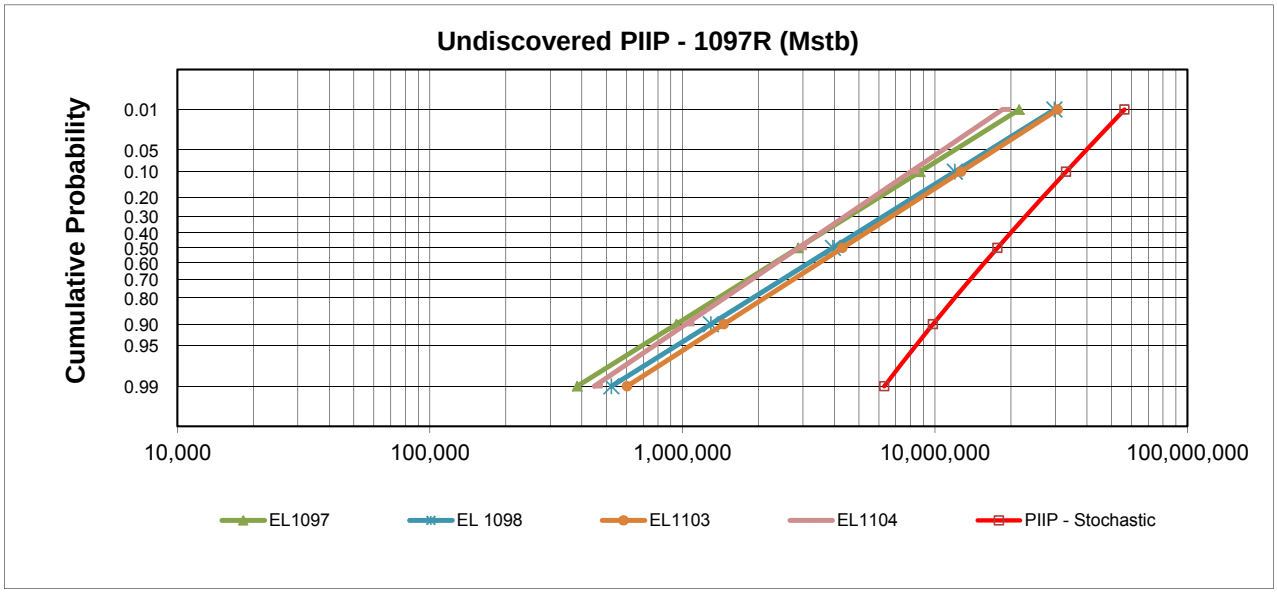


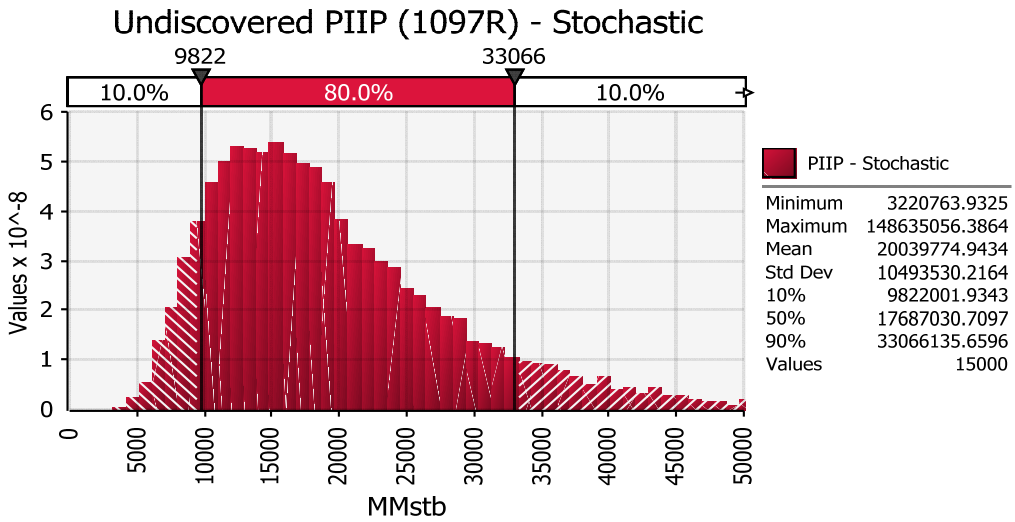
			Low	Best	High
EL1070	Green Point Shale	Mstb	28,401	99,809	350,753
EL1120	Green Point Shale	Mstb	28,886	102,702	365,157
EL1097R	Green Point Shale	Mstb	418,122	766,044	1,456,179
Prospective Resources		**Mstb**	**475,409**	**968,555**	**2,172,089**



Company Evaluated: Shoal Point Energy
Appraisal For: Shoal Point Energy - West Coast Newfoundland
Permit / Block: EL1097, EL 1098, EL1103, EL1104

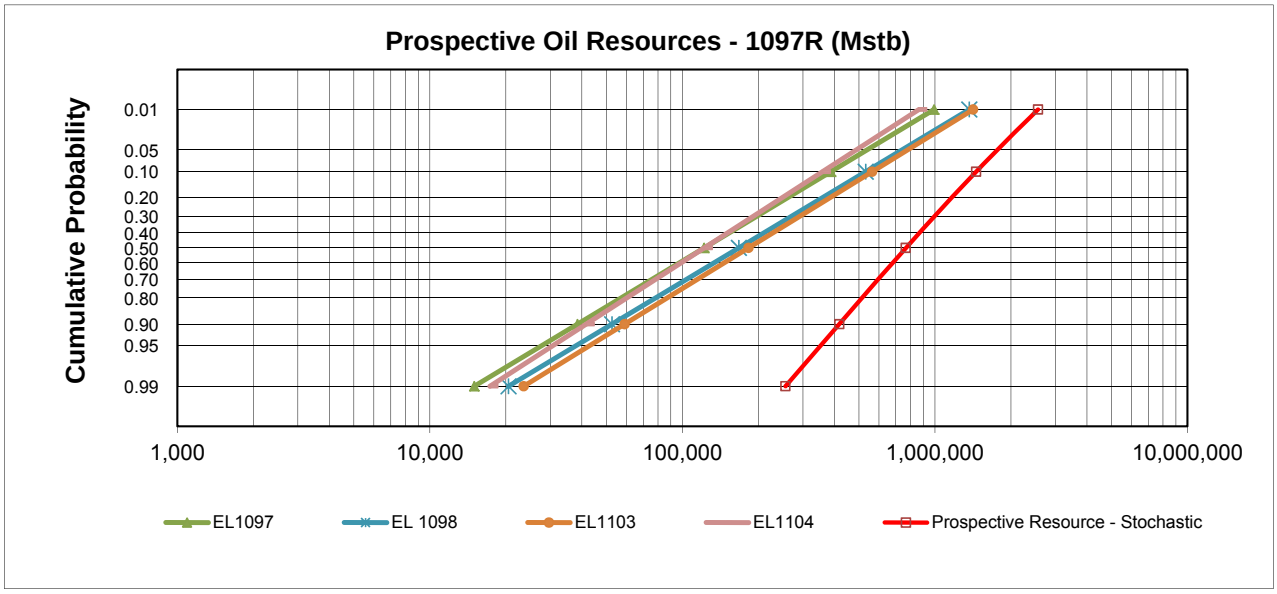
			Low	Best	High
EL1097	Green Point Shale	Mstb	947,273	2,874,808	8,724,538
EL 1098	Green Point Shale	Mstb	1,296,687	3,944,248	11,997,571
EL1103	Green Point Shale	Mstb	1,458,890	4,302,795	12,690,505
EL1104	Green Point Shale	Mstb	1,033,004	2,878,634	8,021,778
Undiscovered PIIP		**Mstb**	**9,822,002**	**17,687,031**	**33,066,136**

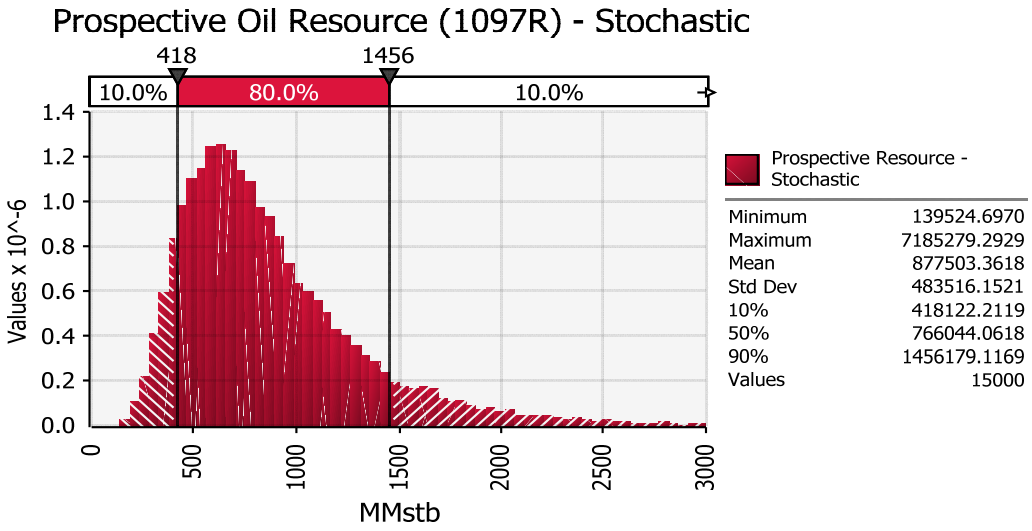




Company Evaluated: Shoal Point Energy
Appraisal For: Shoal Point Energy - West Coast Newfoundland
Permit / Block: EL1097, EL 1098, EL1103, EL1104

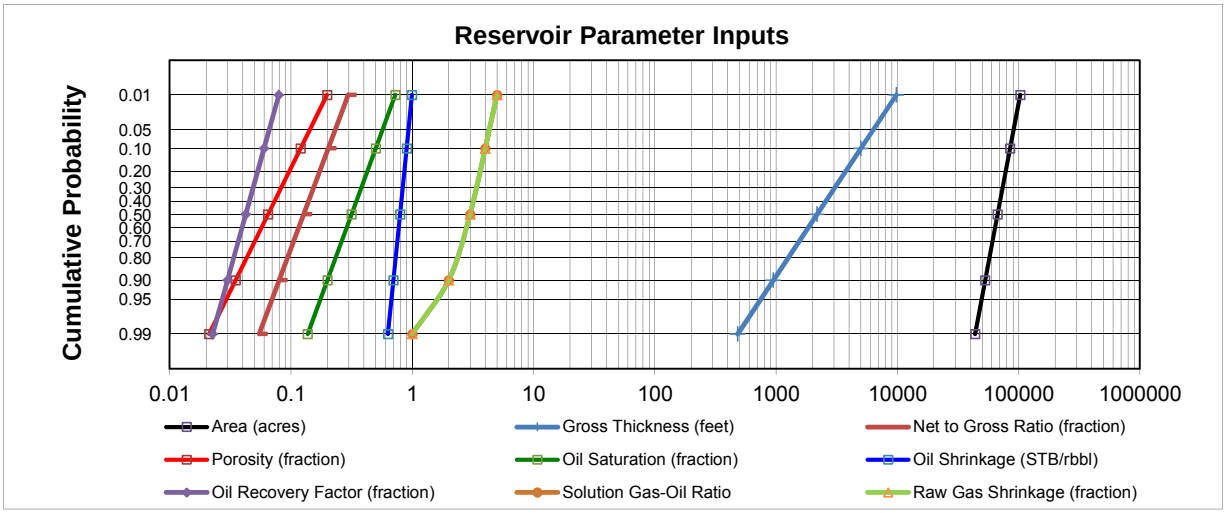
			Low	Best	High
EL1097	Green Point Shale	Mstb	38,430	121,968	387,096
EL 1098	Green Point Shale	Mstb	52,616	167,340	532,209
EL1103	Green Point Shale	Mstb	59,039	182,552	564,463
EL1104	Green Point Shale	Mstb	41,598	122,130	358,571
Prospective Resources		**Mstb**	**418,122**	**766,044**	**1,456,179**

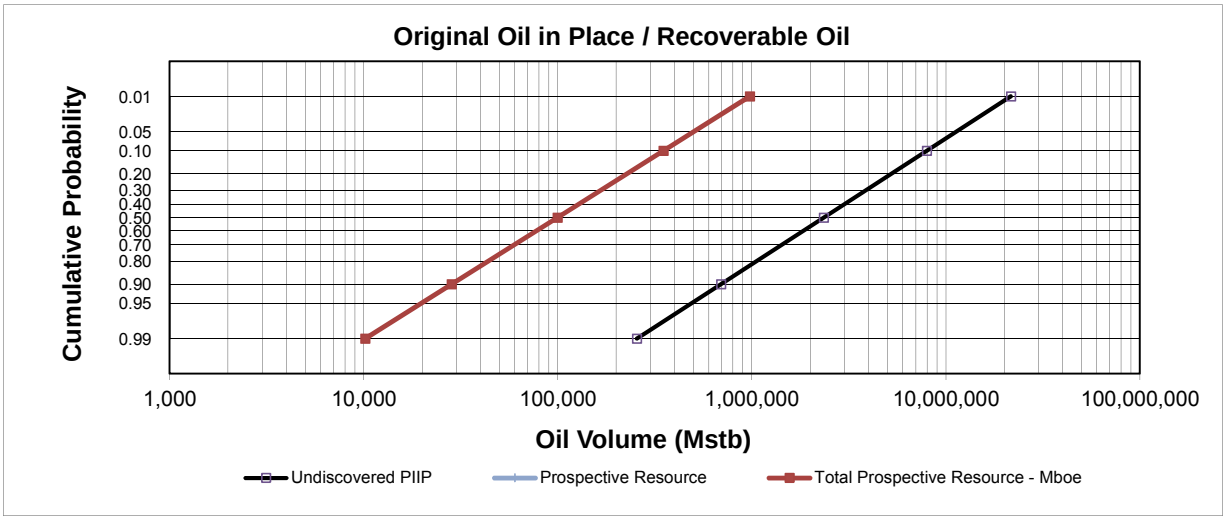




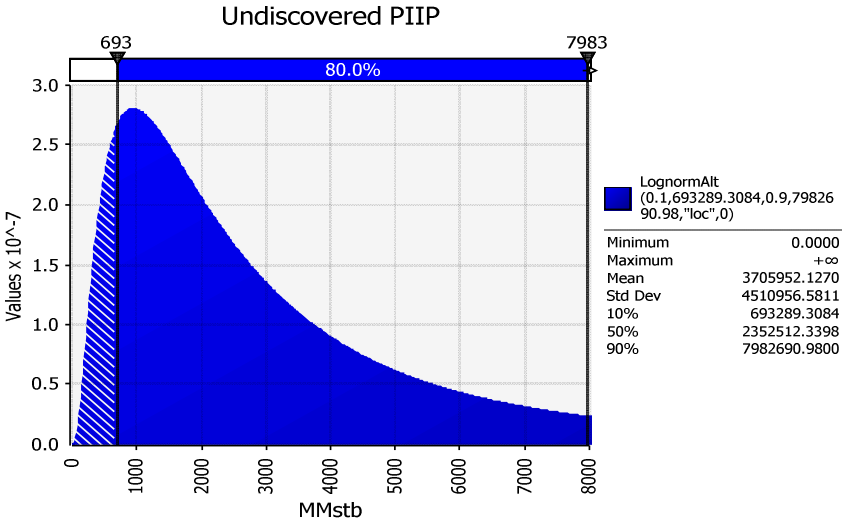
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1070
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

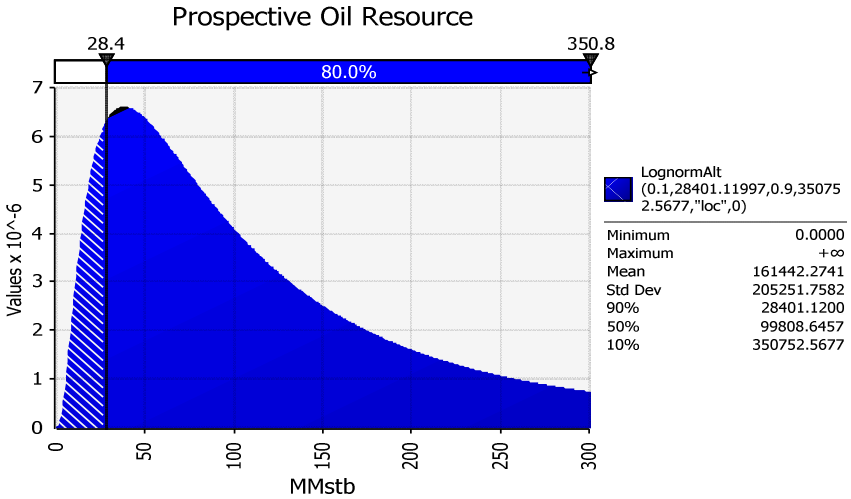
		Low	Best	High
Area	acres	53,000	67,119	85,000
Gross Thickness	feet	950.0	2,179.4	5,000.0
	metres	289.6	664.3	1,524.0
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**693,289**	**2,352,512**	**7,982,691**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**28,401**	**99,809**	**350,753**





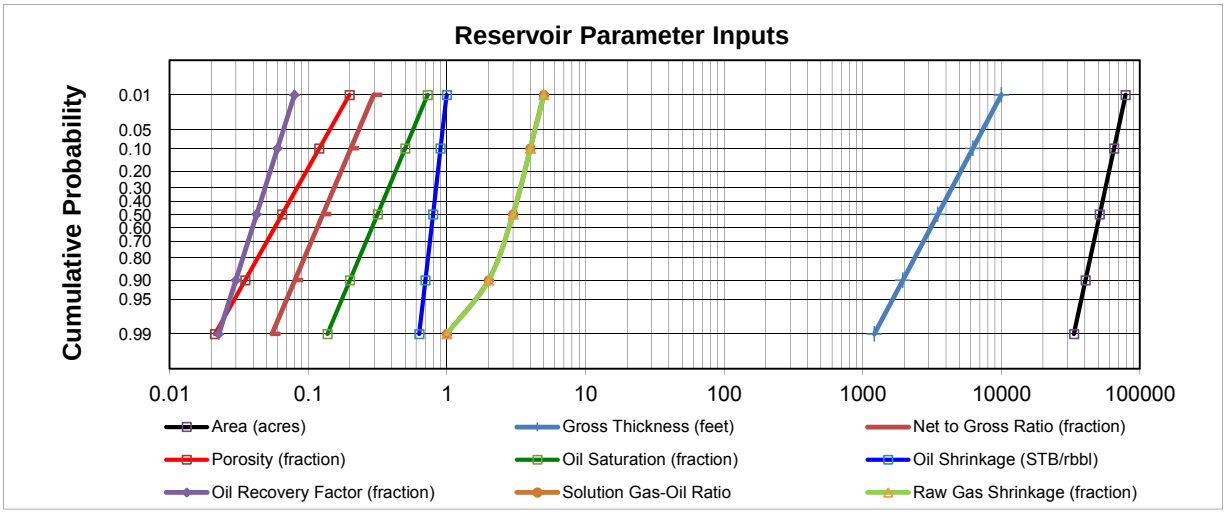
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1070
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

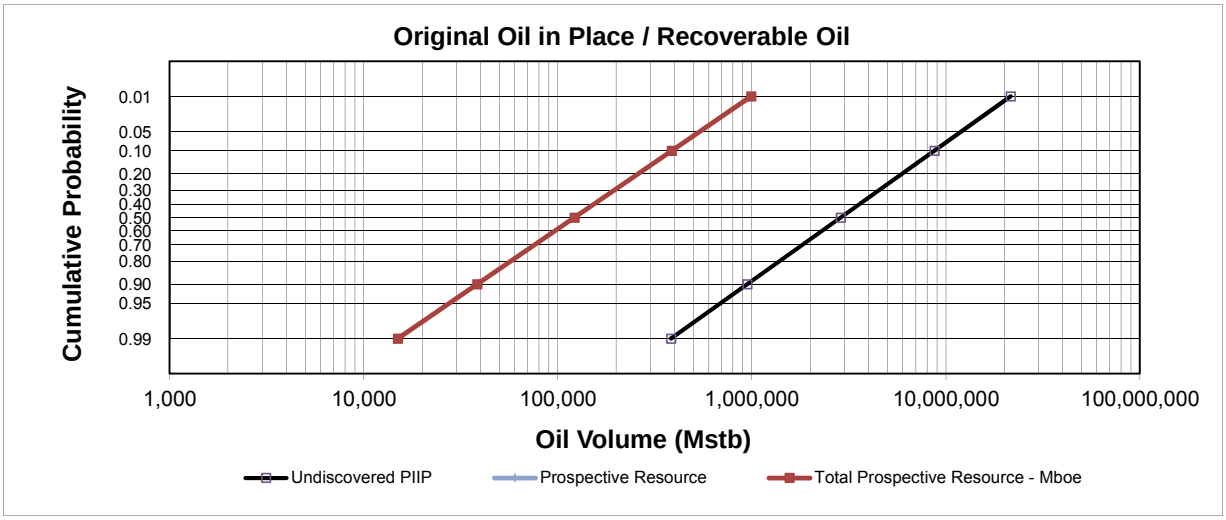




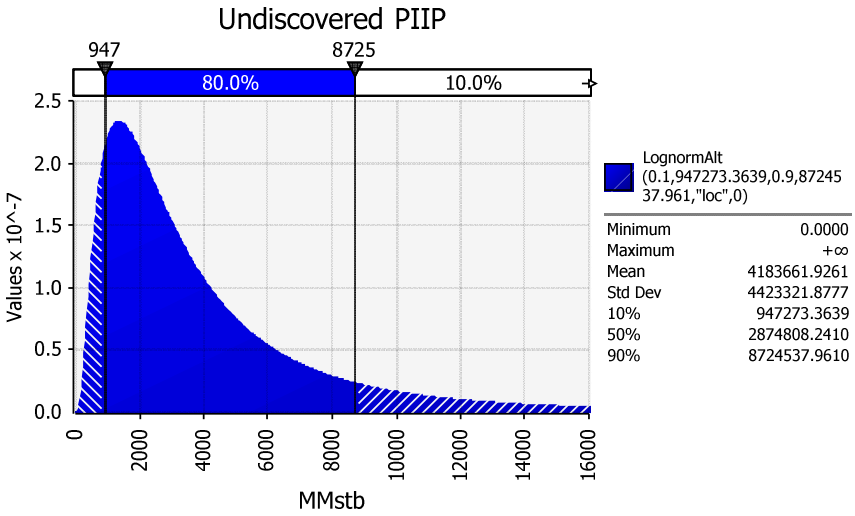
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1097
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

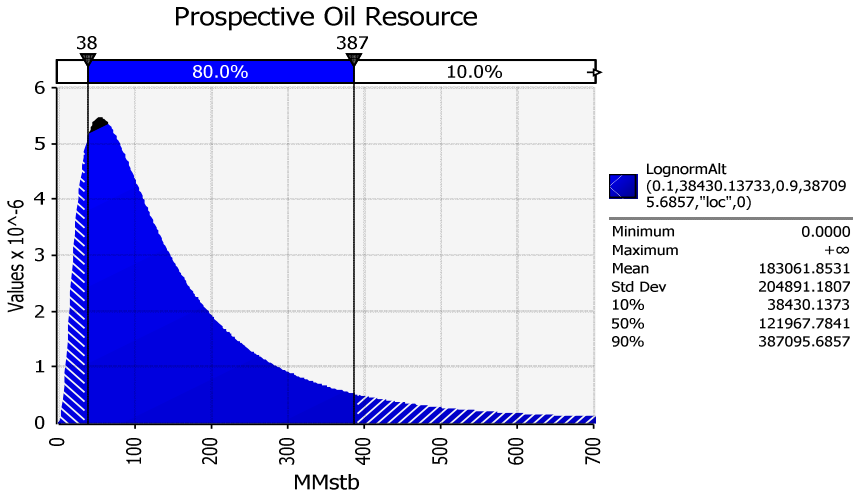
		Low	Best	High
Area	acres	40,500	51,308	65,000
Gross Thickness	feet	1,950.0	3,484.1	6,225.0
	metres	594.4	1,061.9	1,897.4
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**947,273**	**2,874,808**	**8,724,538**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**38,430**	**121,968**	**387,096**





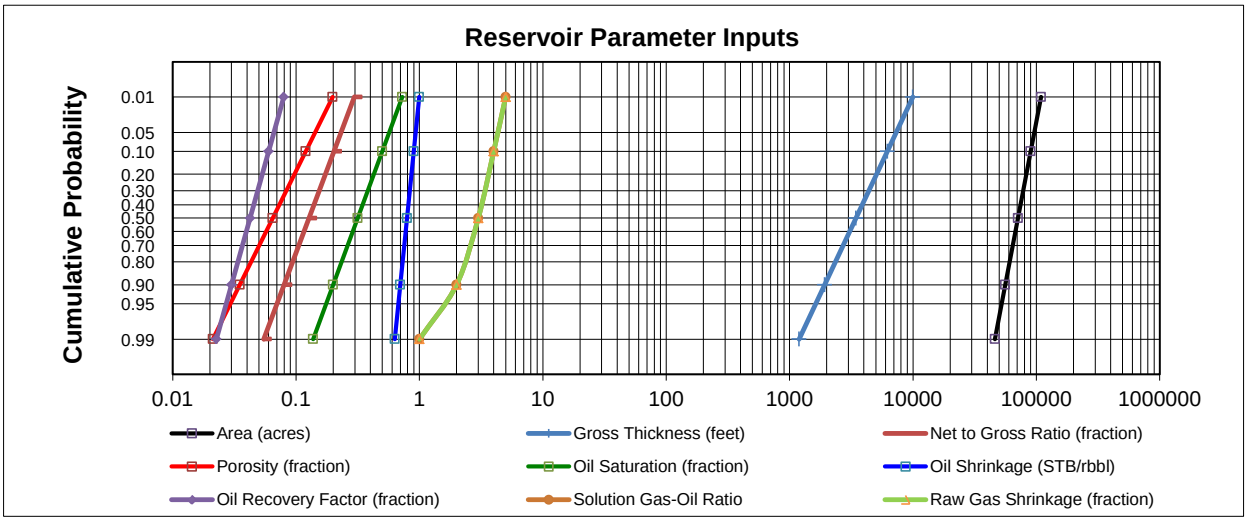
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1097
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

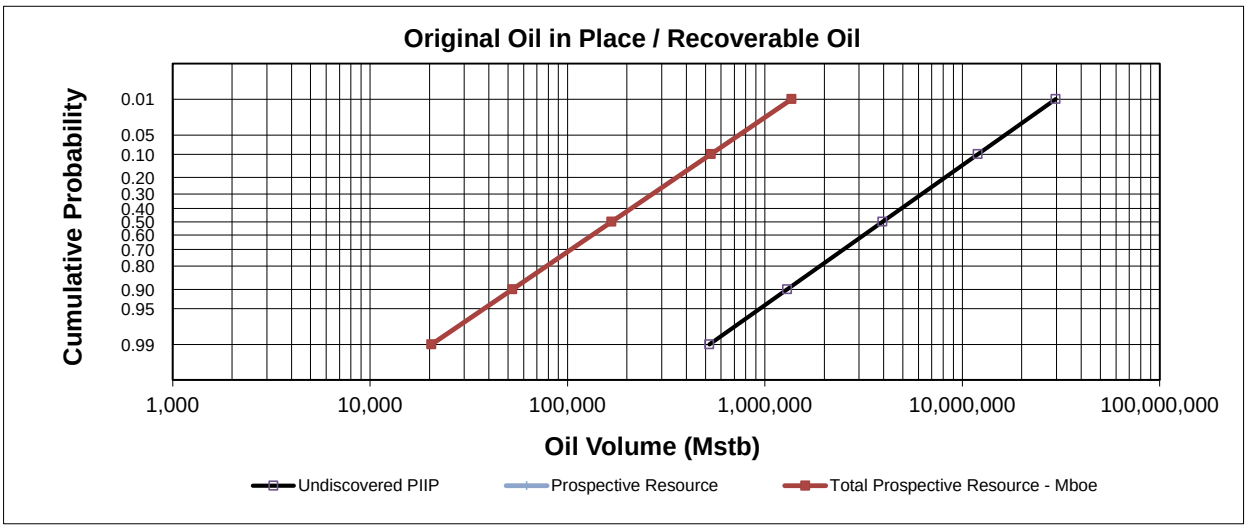




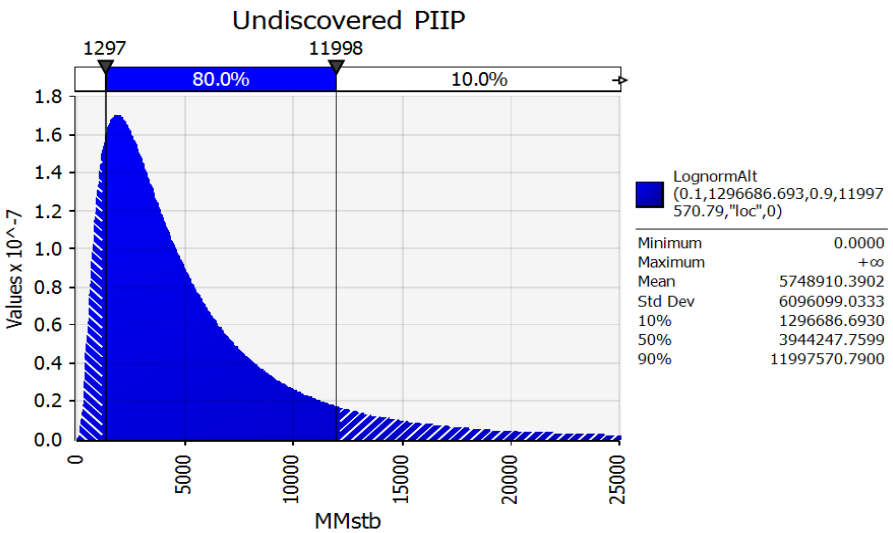
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL 1098
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

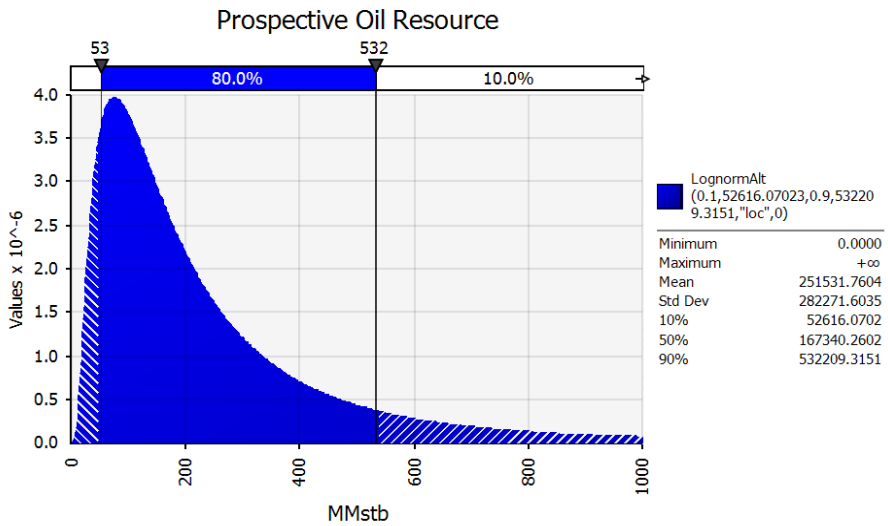
		Low	Best	High
Area	acres	56,000	70,993	90,000
Gross Thickness	feet	1,925.0	3,454.7	6,200.0
	metres	586.7	1,053.0	1,889.8
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**1,296,687**	**3,944,248**	**11,997,571**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**52,616**	**167,340**	**532,209**





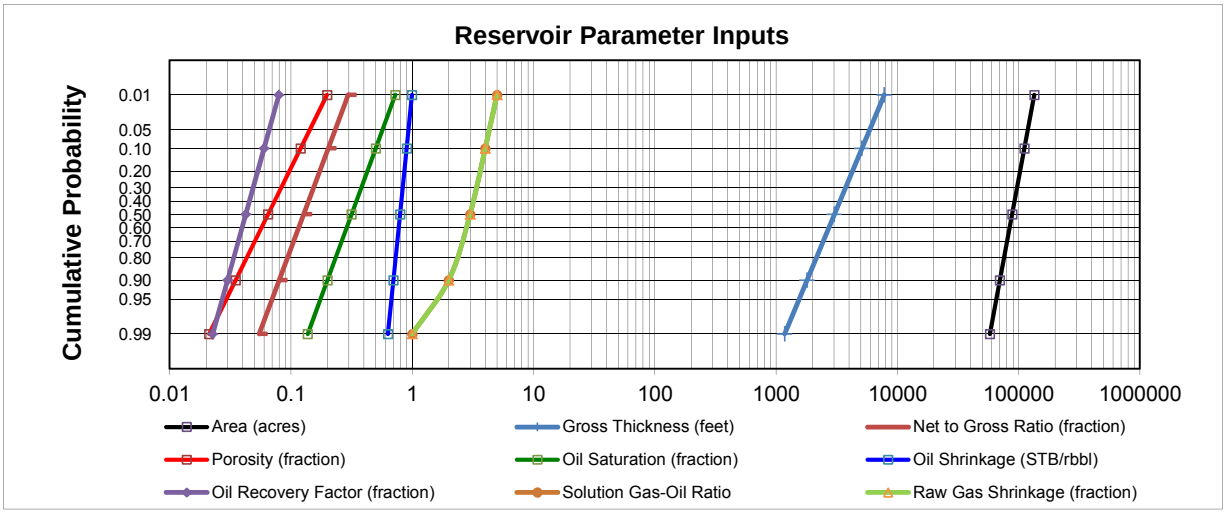
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL 1098
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

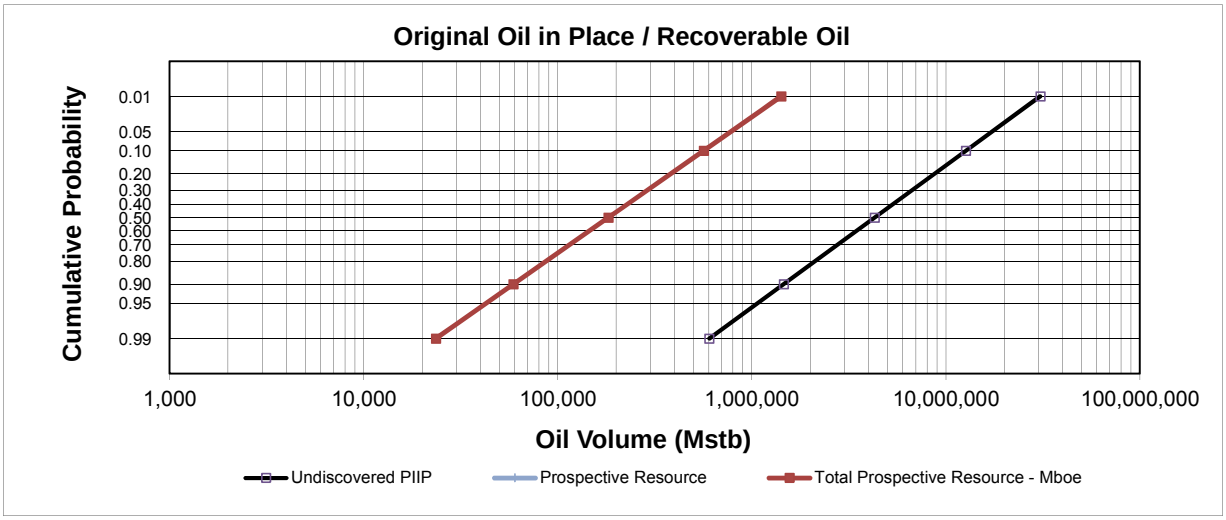




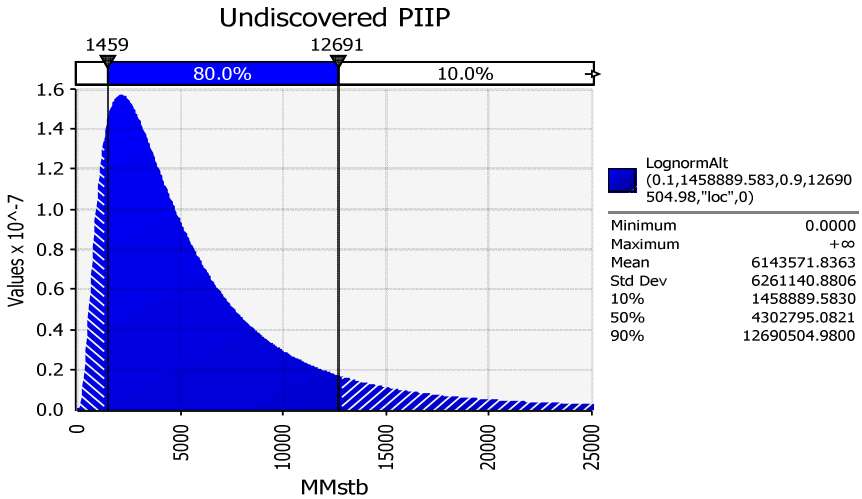
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1103
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

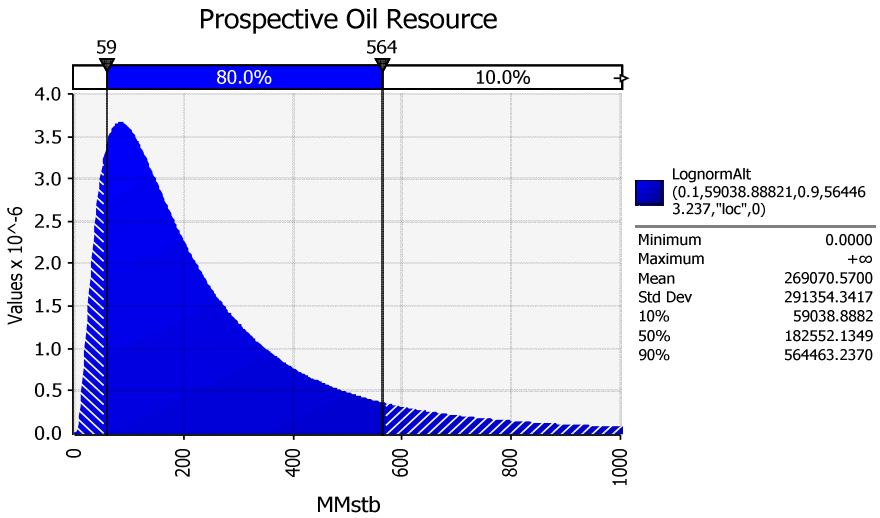
		Low	Best	High
Area	acres	70,000	88,306	111,400
Gross Thickness	feet	1,800.0	3,029.9	5,100.0
	metres	548.6	923.5	1,554.5
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**1,458,890**	**4,302,795**	**12,690,505**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**59,039**	**182,552**	**564,463**





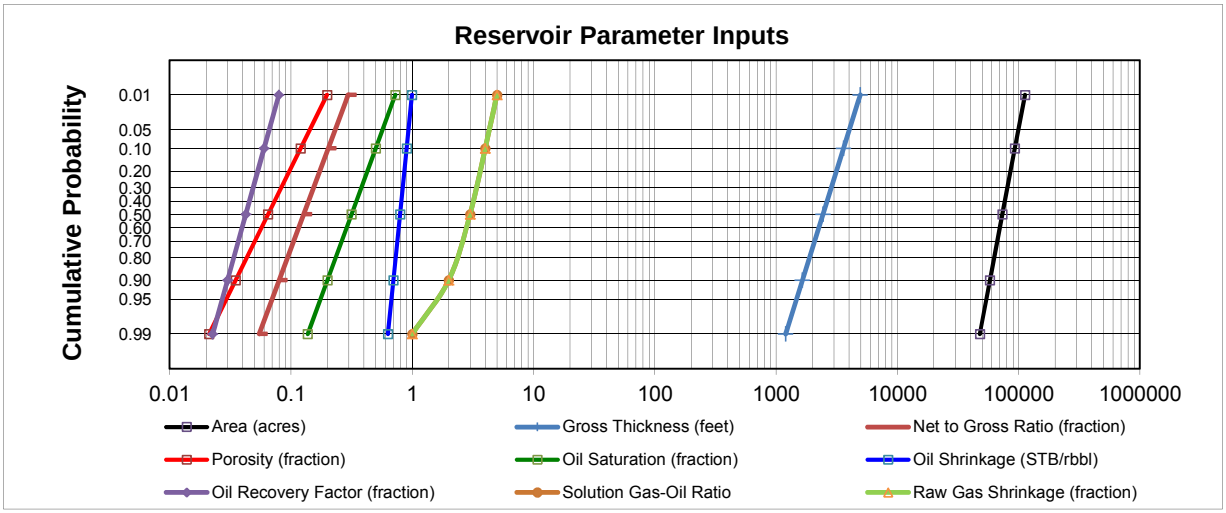
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1103
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

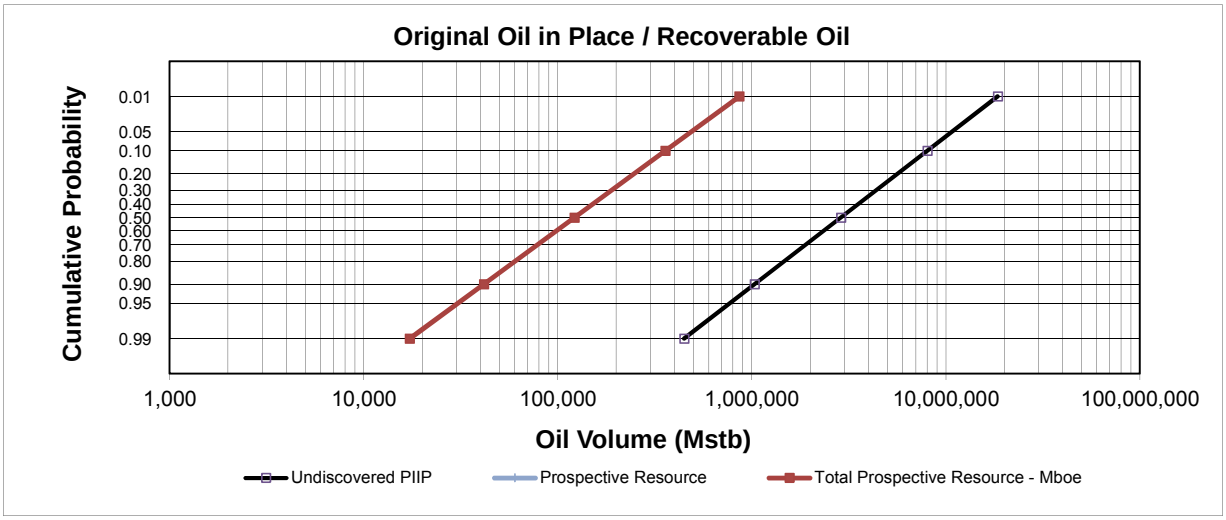




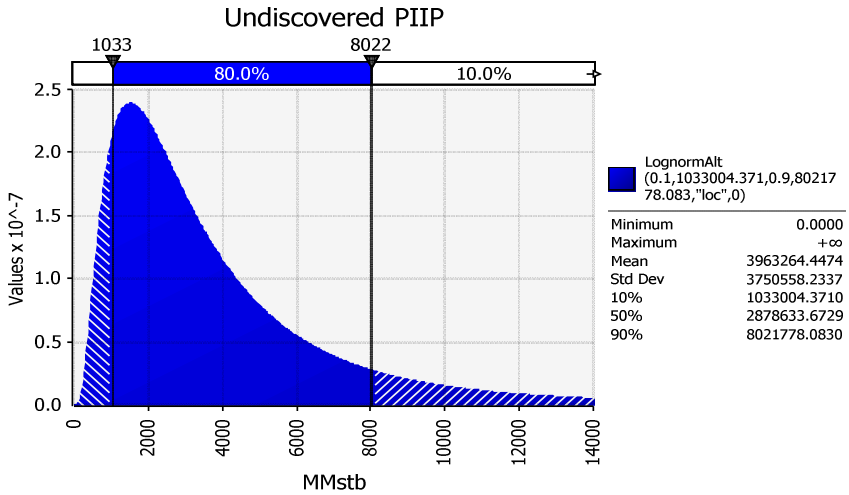
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1104
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

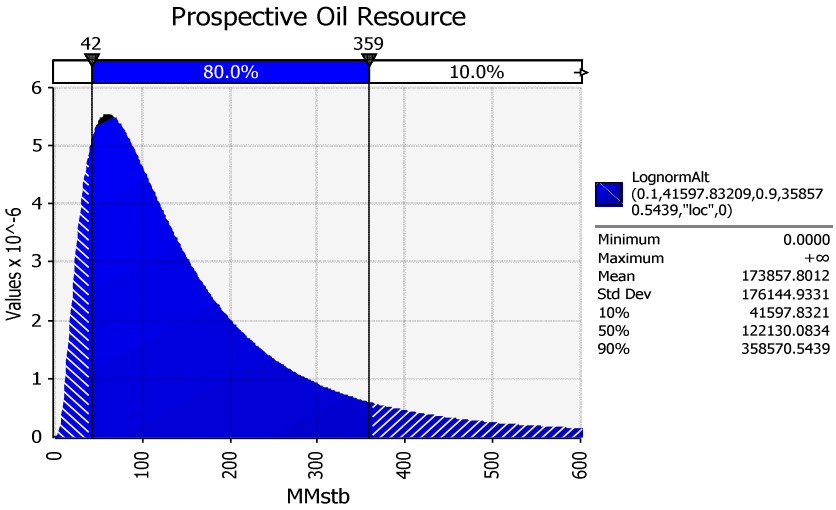
		Low	Best	High
Area	acres	58,000	73,444	93,000
Gross Thickness	feet	1,650.0	2,437.2	3,600.0
	metres	502.9	742.9	1,097.3
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**1,033,004**	**2,878,634**	**8,021,778**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**41,598**	**122,130**	**358,571**





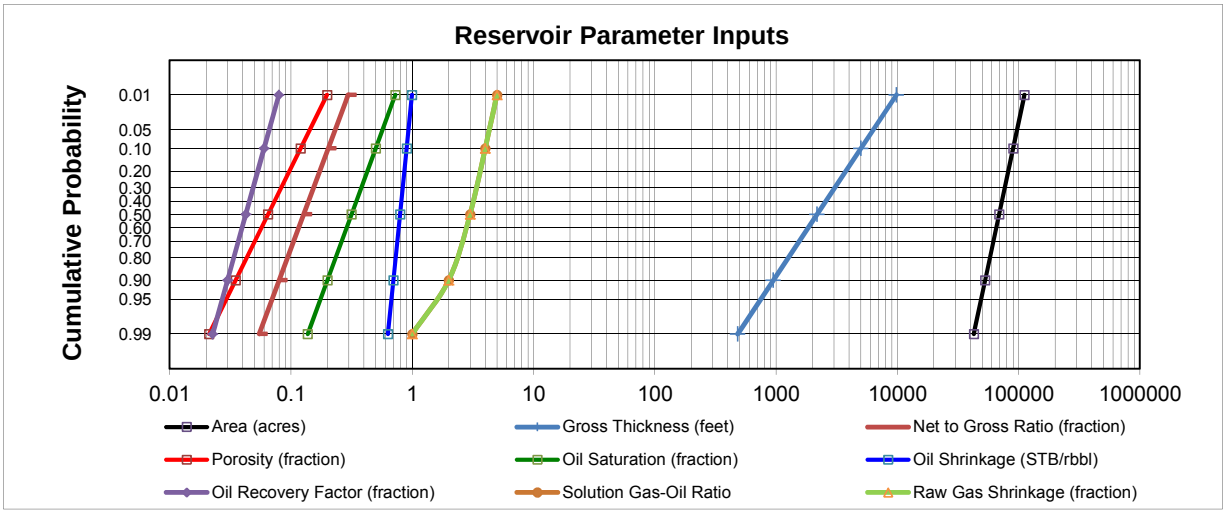
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1104
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

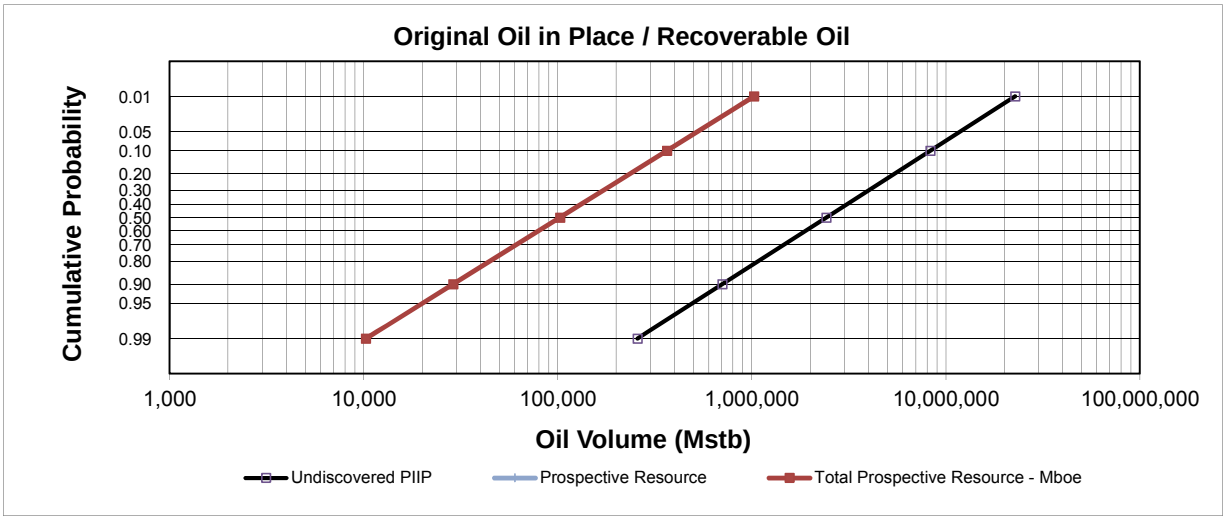




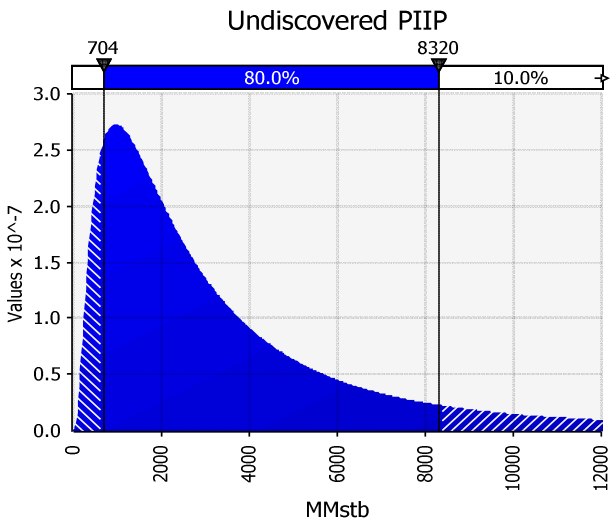
Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1120
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale

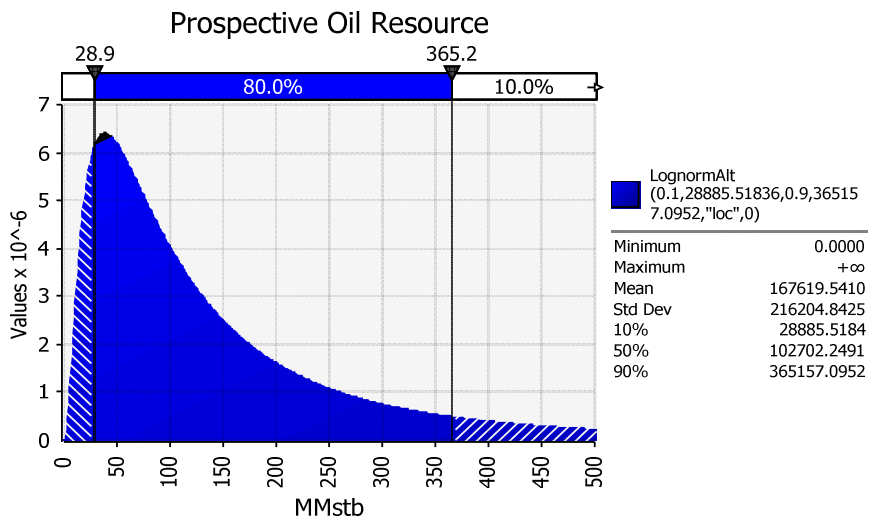
		Low	Best	High
Area	acres	53,000	69,065	90,000
Gross Thickness	feet	950.0	2,179.4	5,000.0
	metres	289.6	664.3	1,524.0
Net to Gross Ratio	fraction	0.08	0.13	0.20
Porosity	fraction	0.04	0.06	0.12
Hydrocarbon Saturation	fraction	0.20	0.32	0.50
Oil Shrinkage	STB/rbbl	0.700	0.794	0.900
Oil Formation Volume Factor	*rbbl/STB*	1.429	1.260	1.111
Undiscovered PIIP	**Mstb**	**704,329**	**2,420,715**	**8,319,780**
Oil Recovery Factor	fraction	0.03	0.04	0.06
Prospective Resource	**Mstb**	**28,886**	**102,702**	**365,157**

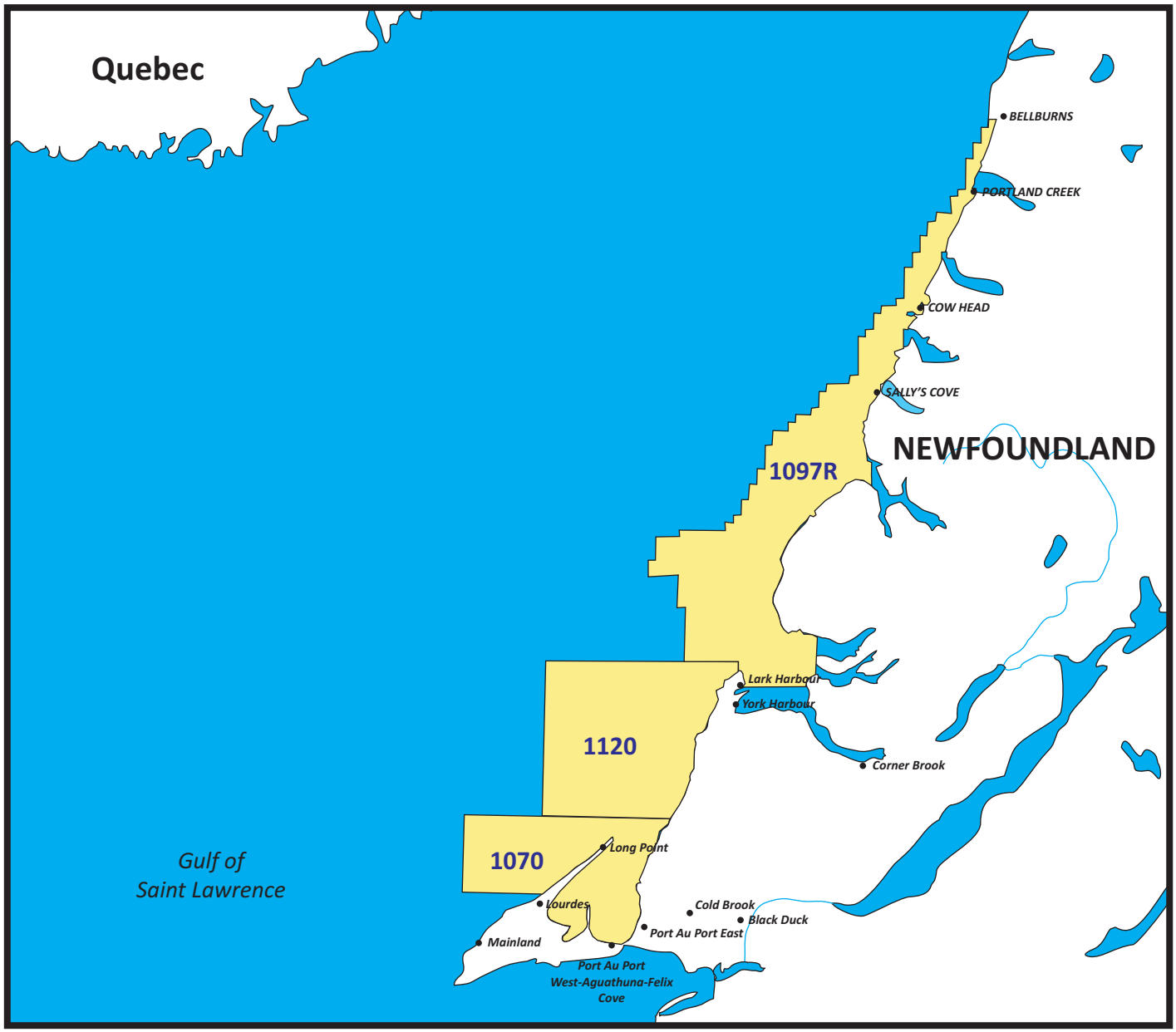




Company Evaluated:	Shoal Point Energy
Appraisal For:	Shoal Point Energy - West Coast Newfoundland
Permit / Block:	EL1120
Entity Name:	Humber Arm Allochthon
Formation:	Green Point Shale







Kilometres

0 15 30 60

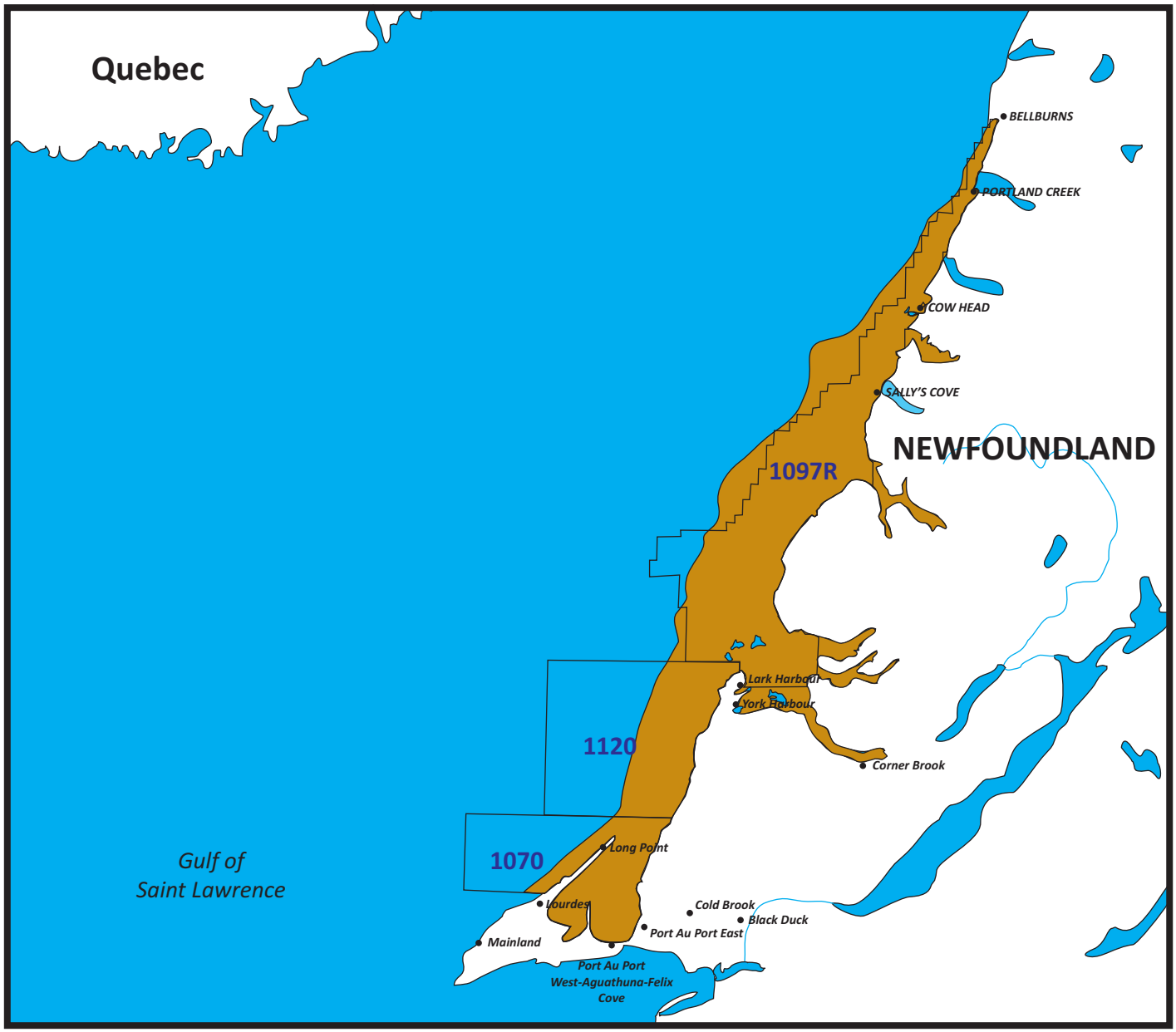
Legend

Shoal Point WI Land

ajm Deloitte.

Shoal Point Energy Ltd. West Coast Newfoundland Exploration Licences

By : laj		Date : 2012/05/01
Project : wcnf lc		
Source : www.cnlopb.nl.ca		



Kilometres

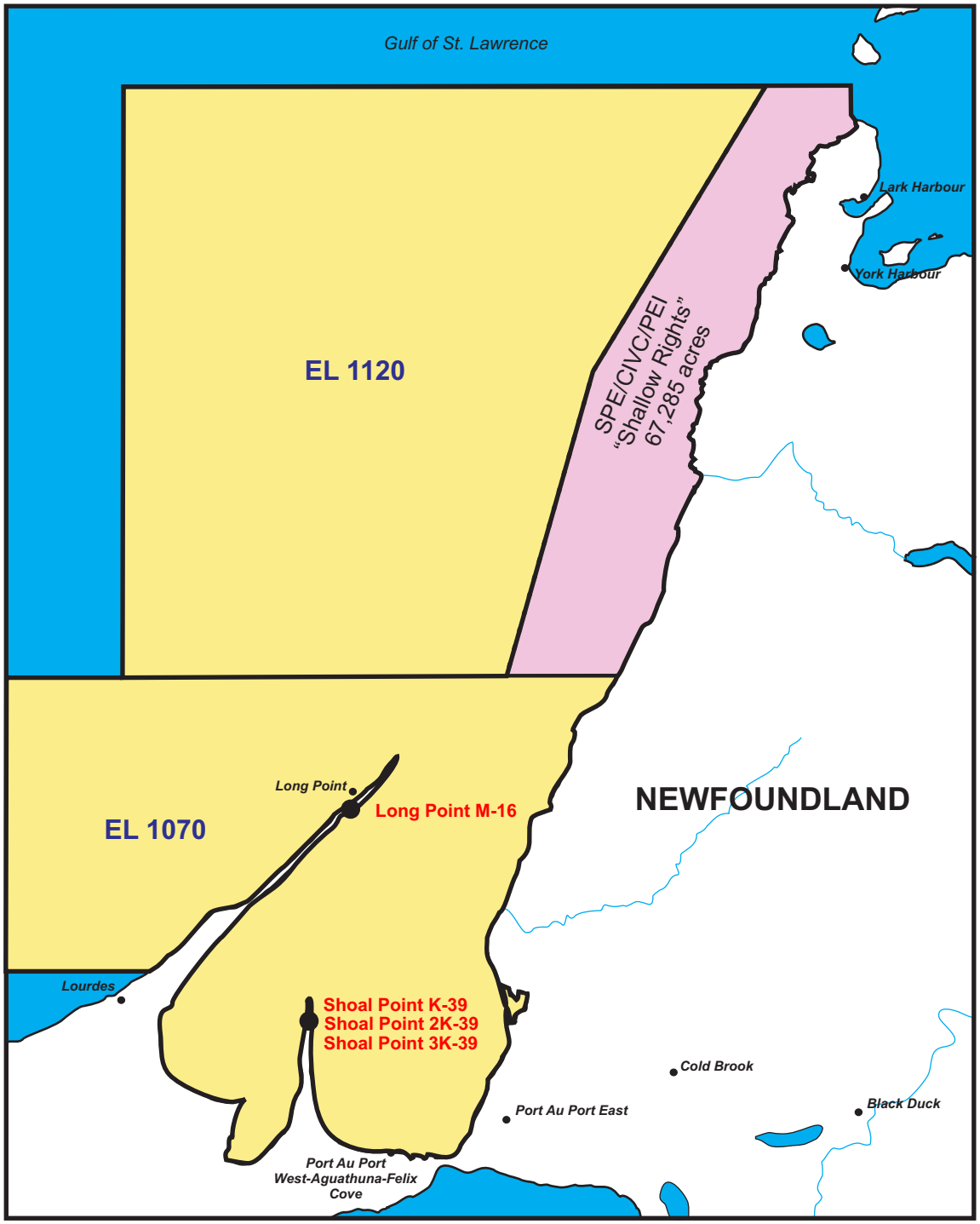
0 15 30 60

Legend
Green Point Shale

ajm Deloitte.

Shoal Point Energy Ltd.
West Coast Newfoundland
Estimated Geological Extent of the Green Point Shale

By : laj		Date : 2012/05/01
Project : wcnf gps		



-5 0 5 10

Kilometres

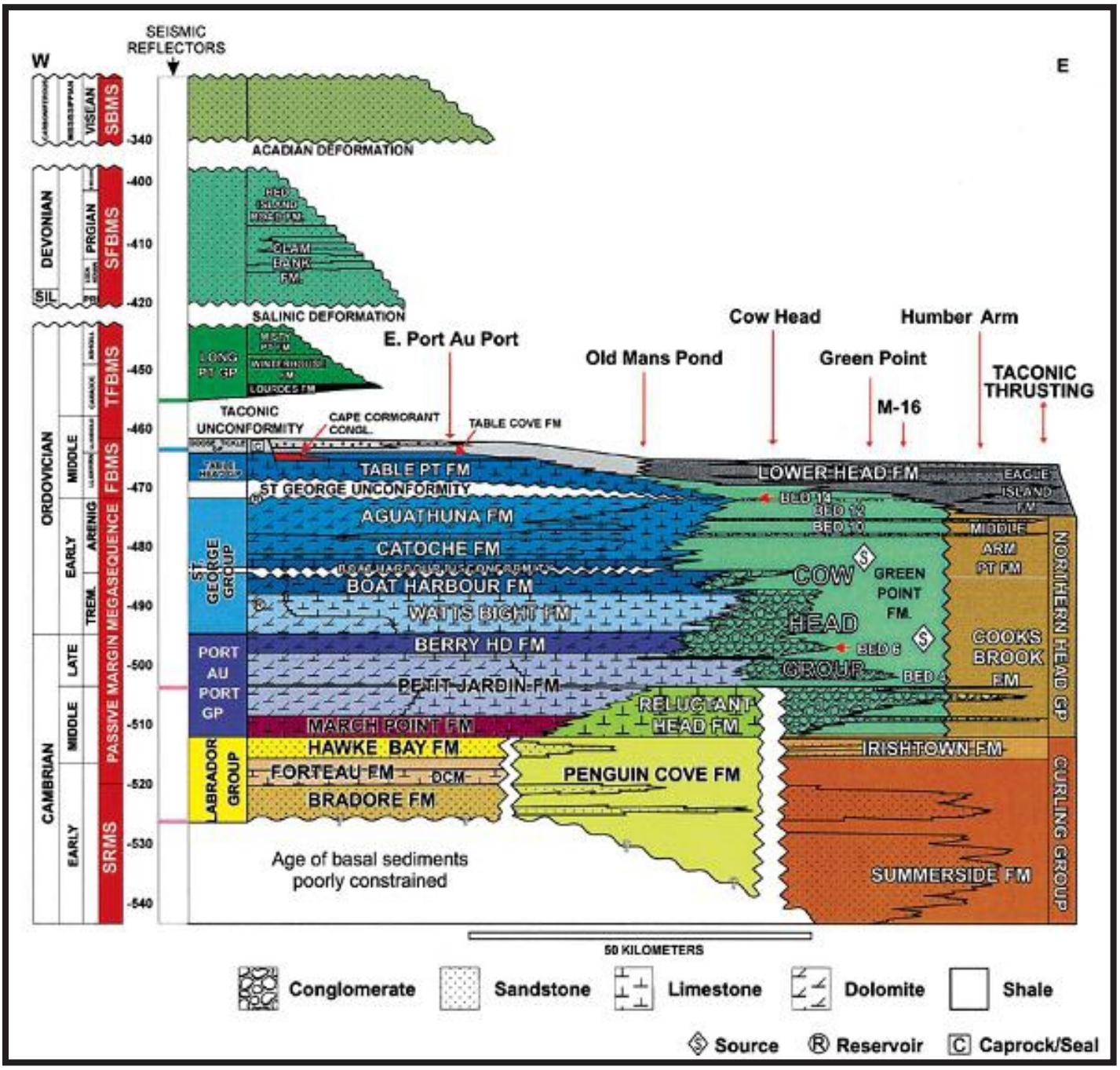
Legend

- abc Well
- Farmout Lands
- Exploration Licenses

ajm Deloitte.

Shoal Point Energy Ltd.
West Coast Newfoundland
Farmout Lands

By : laj	Scale = 1:250,000	Date : 2012/05/01
Project : spe fmolnd		
Source : Shoal Point Energy		



ajm **Deloitte.**

Shoal Point Energy Ltd.
Anticosti Basin, Newfoundland
Stratigraphic Chart
West Newfoundland

By : NWest		Date : 2012/05/01
Project : hmbr arm alcthn		
Source : "G&G Interpretation report", January 2010		

Image source: Birne, David J., "G&G Interpretation Report", January 2010; Cooper et al., 2001; Pg. 19