Morning Star
CONSULTANTS, LLC

Shoal Point Energy Ltd.

NI 51-101 Resource Evaluation
West Coast Newfoundland
Exploration Licenses 1070 & 1120

Effective Date: March 31, 2014

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98 San Jacinto, Suite 520
Austin, Texas 78701
Tel: 512-382-0118
www.morningstarconsultants.com

Shoal Point Energy, Ltd.
#1060 – 1090 West Georgia Street
Vancouver, B.C.V6E-3V7

May 31, 2014

Gentlemen:

Pursuant to your request, Morning Star Consultants, LLC (Morning Star) has prepared an independent estimate of the future gross reserves for certain leasehold interests of Shoal Point Energy, Ltd. (Shoal Point Energy). The properties included within this evaluation are comprised of Blocks EL 1070 and EL 1120 located in eastern Newfoundland, Canada. The properties are operated by farmout partner Black Spruce Exploration who is the designated operator of the properties.

This evaluation has been prepared in accordance with NI 51-101 guidelines and requirements. The results included herein do not represent a Fair Market Value (FMV) assessment of Shoal Point Energy's upstream assets by Morning Star.

This report documents the results of our independent evaluation of the total 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 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 when applicable. 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. 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 Morning Star. Morning Star 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.

In the preparation of this evaluation, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Shoal Point Energy has supplied the basic data utilized in this study. In the preparation of this evaluation, we have not been advised of any legal, regulatory or political obstacles that would significantly alter the ability to proceed with the further development of the project.

Reference documents utilized in preparing this evaluation are as follows:

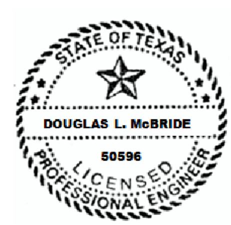
- Exhibit A: Bibliography
- Exhibit B: Definitions
- Exhibit C: Professional Qualifications
- Exhibit D: Representation Letter
- Exhibit E: Lease Base Map
- Exhibit F: Stratigraphic Section of the Green Point Shale
- Exhibit G: Probability Distribution Functions
- Exhibit H: Historical Pricing Data

Morning Star is independent of Shoal Point Energy 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").

Please let us know if we can be of further service in this matter.

Very truly yours,
MORNING STAR CONSULTANTS F-10475

Douglas L. McBride, P.E.
President and Chief Executive Officer



Independent Petroleum Consultants Consent

The undersigned firm of independent qualified reserves evaluators 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, 2014.

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 Morning Star Consultants.

In the course of this evaluation, Shoal Point Energy, Ltd. provided Morning Star 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 conducting the evaluation and upon which this report is based, were obtained from public records, other operators and from Morning Star's 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.

An executed "Representation Letter" dated May 21, 2014 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 resource volumes. This letter is included within.

A field inspection and environmental/safety assessment of the properties was beyond the scope of our engagement 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 reserves data are the responsibility of the Company's management. Our responsibility was to express an opinion on the resource data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGEH Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

Those standards required that we perform an evaluation to obtain reasonable assurance as to whether the resource data are free of material misstatement. This evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGEH Handbook.

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. Morning Star 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.

CORPORATE PERMIT TO PRACTICE
Morning Star Consultants
Texas Board of Professional Engineers
License # F-10475

Procedure

Morning Star 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.

Detailed Methodology

In preparing our estimates for resource volumes as of March 31, 2014, for Shoal Point Energy, we relied upon data furnished by Shoal Point Energy with respect to property interests owned, geological structural and isopach maps, well logs, petrophysical analysis of various wells, core analyses, geochemical data and pressure measurements. These data were accepted as authentic and sufficient for determining the resource volumes unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. Certain technical personnel of Shoal Point Energy were responsible for the preparation of the data reviewed. These personnel assembled the necessary data and maintained the data and work papers in an orderly manner. We consulted with these technical personnel and had access to their work papers and supporting data in the course of our review. Our review included such tests and procedures as we considered necessary under the circumstances to render the conclusions set forth herein. This data included the detailed assessment of original oil in place (OOIP) and the remaining oil in place estimated by the Shoal Point Energy and their agents.

This evaluation included data for only those wells that have been drilled within nearby licenses in proximity to Shoal Point Energy's holdings as of March 31, 2014.

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 misstatement. The internal reserves evaluations prepared by Shoal Point Energy were reviewed as part of our data assimilation effort.

Reserve and Resource Evaluation

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserve Categories

Potential reserves and resource volumes have been evaluated by Morning Star in accordance with the preceding NI 51-101 definitions and 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

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

Reserves Status Categories

Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves

Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing

Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing

Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) wells not capable of production for mechanical reasons. Behind pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves

Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery project. The stochastic reserves included herein conform to the NI 51-101 guidelines. The reserve definitions and standards are discussed in the following section.

The key part of the resource definitions relates to the classification of estimated recoverable quantities from accumulations that have been discovered but are currently considered as sub-commercial, and from those accumulations that have yet to be discovered. These are termed Contingent Resources and Prospective Resources, respectively.

Total Petroleum-Initially-In-Place

Total Petroleum-initially-in-place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-initially-in-place is, therefore, that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced there from, plus those estimated quantities in accumulations yet to be discovered. Total Petroleum-initially-in-place may be subdivided into Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, with Discovered Petroleum-initially-in-place being limited to known accumulations.

It is recognized that all Petroleum-initially-in-place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability. A portion of those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Discovered Petroleum-Initially-In-Place

Discovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced there from. Discovered Petroleum-initially-in-place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

Contingent Resources

Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. It is recommended that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe, the estimated recoverable volumes for the accumulation be classified as contingent resources.

Contingent Resources may include, for example, accumulations for which there is currently no viable market, committed project financing that would allow the development of the project, or where commercial recovery is dependent upon the development of new technology.

Undiscovered Petroleum-Initially-In-Place

Undiscovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum-initially-in-place is classified as Prospective Resources, as defined below.

Prospective Resources

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

Geological Risk Factors

A total of six criteria are considered in determining the overall geological risk.

1. Source rock – is there thermally mature hydrocarbon source rock present in adequate thickness, extent and organic richness
2. Charge – is the source rock capable of generating hydrocarbon
3. Migration – are there sufficient migration pathways such as faults, fractures and carrier beds to the reservoir
4. Reservoir rock – does the reservoir have favorable parameters such as thickness, pore space and the ability to allow fluid flow
5. Trap / Closure – does closure of the reservoir exist in terms of adequate areal extent and vertical relief
6. Seal / Containment – are there effective sealing rocks present to ensure that containment has occurred

Examples of Typical Resource Plays

One of the defining aspects of Resource Play reservoirs is the existence of a continuous hydrocarbon accumulation over a large areal extent. Generally speaking, unconventional reservoirs meet most of the criteria required for classification as Resource Plays. In 1977, the Energy Research and Development Association (now Department of Energy) identified four types of unconventional gas accumulations: tight gas, Devonian shale, geopressured water, and methane from coal. Resource Plays frequently encompass the following types of hydrocarbon deposits:

1. Shale Gas Reservoirs
2. Tight Gas Reservoirs
3. Tight Oil Reservoirs
4. Coalbed Methane Reservoirs
5. Basin Centered Gas Systems

The Green Point Shale is identified at this time as a Tight Oil Reservoir.

Graphical Representation

As shown below, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

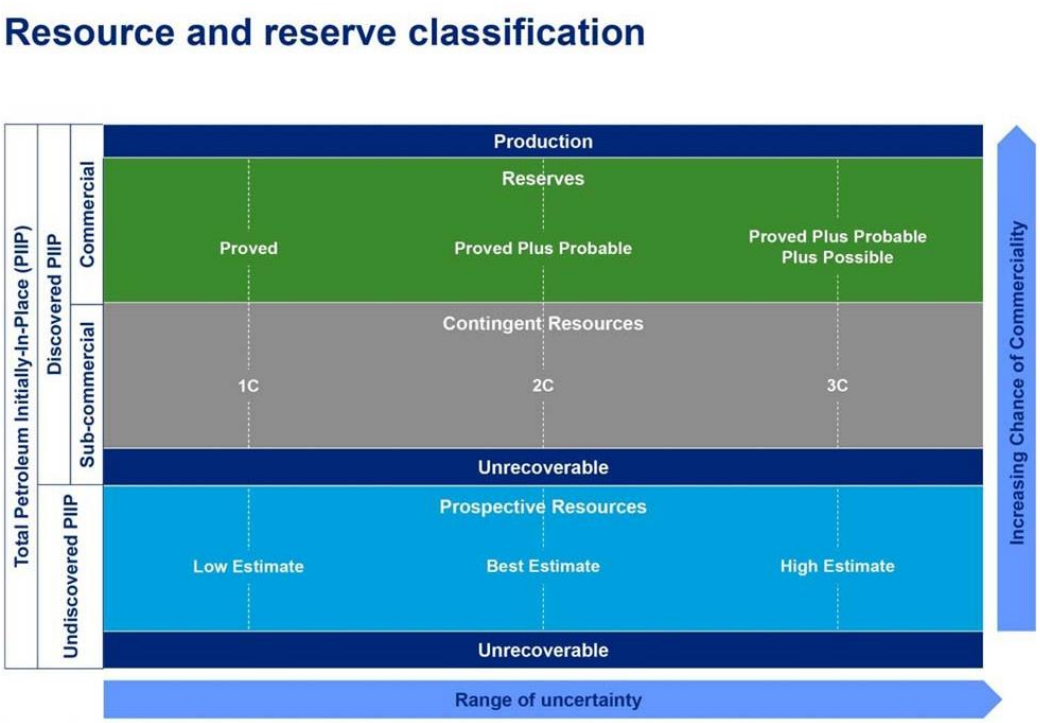


Image adapted from: SPE-PRMS, 2007

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of reserves; therefore, in general, there should be at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate. In addition, an equivalent probability value of 10% should, in general, be used for the High Estimate. Where deterministic methods are used, a similar analogy to the reserves definitions should be followed.

As one possible example, consider an accumulation that is currently not commercial due solely to the lack of a market. The estimated recoverable volumes are classified as Contingent Resources, with Low, Best and High estimates. Where a market is subsequently developed, and in the absence of any new technical data, the accumulation moves up into the Reserves category and the Proved Reserves estimate would be expected to approximate the previous Low Estimate.

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.

Reserve and Resource 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 (P90) 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 (P50) 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 (P10) 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". F or 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).

Statistical Analysis

The two licenses included within this report are currently categorized as Prospective Resources. As a result, the statistical method of analysis was not utilized within our evaluation.

Stochastic - Probabilistic Methods

Because of the uncertainty inherent in reservoir parameters, stochastic - 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 resources. 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.

Morning Star utilized Crystal Ball software to prepare our stochastic resource estimates. Analysis output includes cumulative frequency resource distribution curves and estimates of un-risked and risked resource volumes.

Cumulative frequency curves show how the volumes for a play are distributed. These calculations include the average volumes for a play (P50), volumes for the best 10 percent of the wells (P10), the minimum volumes developed by 90 percent of the wells (P90).

In preparing a resource estimate, Morning Star 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 (P90) and high (P10) values for each parameter. To help test the reasonableness of the proposed range, a minimum (P99) and maximum (P1) 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 P90, P50, and P10 result which comprise Morning Star's estimated range of PIIP or recoverable resource.

The results appearing in this report represent interpolated P90 and P10 values. As defined by COGEH (and the Petroleum Resource Management System "PRMS"), the P50 estimate is the "best estimate" for reporting purposes.

Based upon our evaluation, the properties owned by Shoal Point Energy are categorized as Prospective Resources and are summarized in table below.

Resource Class	Gross Low MMstb	Gross Best MMstb	Gross High MMstb	Working Interest Low MMstb	Working Interest Best MMstb	Working Interest High MMstb
Cumulative Production	0	0	0	0	0	0
Remaining reserves	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	0	0	0	0	0	0
Unrecoverable	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	177.3	428.4	908.6	177.3	428.4	908.6
Unrecoverable	2,874.5	6,119.7	10,889.7	2,874.5	6,119.7	10,889.7
Total undiscovered PIIP	3,051.8	6,548.1	11,798.3	3,051.8	6,548.1	11,798.3
Total PIIP	3,051.8	6,548.1	11,798.3	3,051.8	6,548.1	11,798.3

Notes: (1) Effective March 31, 2014.
(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.

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.

Land Schedule and Maps

Shoal Point Energy provided the information pertaining to license ownership which included lessor and lessee royalty burdens. This ownership data has been accepted as presented and has not been independently verified by Morning Star.

Shoal Point Energy earned a 45.5 percent interest in the eastern portion of the license by drilling the 2K-39 well in 2008. Pursuant to earning, Shoal Point Energy formed an agreement with partners in the license, to trade deep rights for an increased percentage of shallow rights. As a result, Shoal Point Energy became operator of the shallow rights (Late Cambrian to Ordovician age sediments); their partner at that time was Canadian Imperial Venture Corp. (CIVC).

As of September 25, 2011, Shoal Point Energy has increased their working interest to 100 percent in the shallow rights, to the base of the Green Point Shale, of Exploration License

1070. Shoal Point Energy has satisfied the “Period 1” term license requirements by drilling and sampling the sediments within the 2K-39 wellbore. EL 1070 is now subject to an extended “Period 2” term of the license requirements under the “diligent pursuit” clause of the legislation. Shoal Point Energy continues to advance the Green Point Shale prospect by planning and drilling the 3K-39 well. Shoal Point has a farmout agreement with Black Spruce Energy, whereby Black Spruce can earn 40% of Shoal Point’s interests in Western Newfoundland by drilling and completing 3 wells; can increase its’ interest to 50% by drilling and completing a 4th well; and would then have the option to earn an additional 10% (to a total of 60%) by drilling and completing an additional 8 wells (for a total of 12 wells). Shoal Point would participate in all cash flow from first production.

The table below summarizes the historical costs and the estimated near-term future costs for EL 1070.

Exploration License 1070			
	HISTORICAL COSTS		
	Acquisition	**Exploration**	**Total**
January 31, 2014	**$ 4,677,552**	**$ 41,527,854**	**$ 46,205,406**
February 1, 2014 to March 31, 2014	**-**	**52,017**	**52,017**
Total	**$ 4,677,552**	**$ 41,579,871**	**$ 46,257,423**
Total Costs to March 31, 2014			**$ 46,257,423**
	FUTURE COSTS		
Anticipated fracture stimulation-2014			**$ 1,750,000**

We have been advised that the EL #1097R was surrendered in accordance with requirements of the C-NLOPB on January 15, 2014.

No historical costs have been incurred to date for EL 1120 and no future costs are planned at this time.

Geology

The Paleozoic rocks of West Newfoundland have been a site for periodic drilling for oil since 1867 and 1898. This drilling has been encouraged by the historical oil and gas seeps, bituminous residues and oil shales over this 200 kilometer coastline from Port au Port Peninsula to Parson’s Pond. By the end of the 1930’s there were about 38 shallow wells drilled in this area and there are reports that as much or more than 10,000 of barrels were produced for local consumption for use mostly in the fishing industry. Drilling since the 1960’s culminated in 1994-5 with the testing of up to 1742 BOPD from the Port au Port #1 well. The next few wells were unsuccessful.

In 2008 Shoal Point Energy and partners drilled the 2K-39 well from Shoal Point in Port au Port Bay for a deeper hydrothermal dolomite play. This play was unsuccessful but high gas readings, oil shows were encountered in about 500 m of the shallower Upper Cambrian-Lower Ordovician Green Point black shales. Geochemistry of the cuttings reveals that these units are in the oil window, explaining the oil shows. The same rocks units in the offsetting wells and the shoreline outcrops show consistent wide-spread, excellent oil-prone source rocks. These would be the same rocks that sourced the 51°-52° API Port au Port #1 oil as well as all the seeps and shows in the Bay.

These Allochthonous Green Point Shales have had a very complex history where they were first transported then affected by three orogenies, Taconic, Acadian and finally the Alleghenian Orogeny which buried these good source rocks down into the oil window.

These Allochthonous rocks, as found in Port au Port Bay, consist of a series of stacked thrust sheets that are intensely fractured, faulted and folded. From the well evidence, outcrops and location of seeps these rocks are essentially rich thick black source rocks with up to 10% TOC's. Well evidence shows that these units are roughly 1000 meters thick in the middle of the bay. The 2K-39 well revealed a very good zone of about 100 m thick with very high gas readings and oil shows which might be a fracture swarm that might be common in the area. This unit is further enhanced by about 11 units of 1 to 3 meter siltstone beds that may act as carrier beds if artificially fractured.

An initial review of each property was undertaken to determine:

- 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 Morning Star's need to establish volumetric hydrocarbons-in-place.

Detailed procedures specific to the project are discussed in a later section of this report.

Analogies

Based upon current data and information, there are no confirmed commercial analogies for the Green Point Shale.

Royalties and Taxes General

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

Morning Star utilizes a variety of reserves and evaluation products in determining the result sets. In a resource evaluation of this type where the targeted reservoirs have been categorized as Prospective Resources for the purposes of NI 51-101 a detailed economic analysis of the estimated resource volumes has not been prepared.

Price and Market Demand Forecasts

Historical pricing data for Canadian crude is included as Exhibit H as of March 31, 2014. We estimate that current pricing will escalate on average at 5 percent per annum. In preparing the price forecast Morning Star considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The forecasts are Morning Star's interpretation of current available information for this frontier region and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Reference Documents
Q12014 Data and Information

1. US Energy Information Administration
   World Shale Gas and Shale Oil Resource Assessment - May 2013

2. US Geological Survey (USGS)
   Assessment of Undiscovered Oil and Gas Resources of the Ordovician Utica Shale of the Appalachian Basin Province, 2012

3. AAPG Techincial Paper
   Upper Cambrian - Lower Ordovician Green Point Shale, Port au Port Bay, West Newfoundland: Evaluation and Delineation of an Offshore Allochthonous Oil-in-Shale Resource Play – September 12-15, 2010. Author: Jock McCracken, et. al.

4. The Wall Street Journal
   Carrizo Oil & Gas Reports Initial Utica Shale Well Results – January 16, 2004

5. Shoal Point Energy
   An Update on Shoal Point Energy's Green Point Oil-in-Shale Projects: Hydrocarbon Evidence West Newfoundland – March 2014

6. Society of Petroleum Evaluation Engineers
   Monograph 3 – December 2010

7. University of California Museum of Paleontology
   The Ordovician Period – updated 2011
   http://www.ucmp.berkeley.edu/ordovician/ordovician.php

8. GEOLOGY Bulletin of Canadian Petroleum Geology
   Petroleum geochemistry and hydrocarbon potential of Cambrian and Ordovician rocks of western Newfoundland 1
   VOL. 43, NO. 2 (JUNE 1995), P. 187-213

PART 1. ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

Other

API	American Petroleum Institute
API°	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day m3 cubic metres
MBOE	1,000 barrels of oil equivalent
McfGE	1,000 cubic feet of gas equivalent on the basis of 6 McfGEs to 1 bbl of crude oil. McfGEs may be misleading, particularly if used in isolation. A McfGE conversion ratio of 6 McfGEs to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
McfGE/d	1,000 cubic feet equivalent per day
MmcfGE	1,000 McfGE
M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

1.1 NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

“**Reserves**” are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) 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.

"**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 (e.g., 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 classification (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 sub-divide the developed reserves for the pool between developed producing and developed nonproducing. 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.

"**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.

The following terms, used in the preparation of the InSite Report (as defined herein) and this document, have the following meanings:

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Corporation**" or "**Tamarack Valley**" means Tamarack Valley Energy Ltd.

"**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"**future prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated allowances and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate yearend statutory tax rates, taking into account future tax rates already legislated.

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"**gross**" means:

(a) in relation to the Corporation's interest in production or reserves, its "company gross reserves", which are it's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Nonhydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

“**natural gas liquids**” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“**net**” means

(a) in relation to the Corporation’s interest in production or reserves its working interest (operating or nonoperating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and

(c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“**non-associated gas**” means an accumulation of natural gas in a reservoir where there is no crude oil.

“**operating costs**” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“**production**” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“**property**” includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for combustion.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

Morning Star CONSULTANTS, LLC

EXHIBIT C

Certificate of Qualification

I, Douglas L. McBride, a Petroleum Engineer, of 98 San Jacinto, Suite 520, Austin, Texas 78701, USA hereby certify that:

1. I am the President and Chief Executive Officer of Morning Star Consultants LLC ("Morning Star") since 2006, 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, 2014.

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 Texas and graduated with a Bachelor of Science Degree in Engineering in 1975; I have completed non-degree graduate work in Petroleum Engineering at the University of Houston; I have completed business management certification studies at MIT; that I am a Registered Professional Petroleum Engineer in the State of Texas (TBPE #50596); and I have thirty nine years of petroleum engineering, petrophyscial, geological and geochemical experience. I am a member of the Society of Petroleum Engineers, American Association of Petroleum Geologists, Society of Professional Well Log Analysts and the American Society of Mechanical Engineers.

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.

Douglas L. McBride, PE.

May 31, 2014

Date

EXHIBIT D

SHOAL POINT energy

May 21, 2014

Morning Star Consultants LLC
Suite 520, 98 San Jacinto
Austin, Texas, 78701

Re: Standard Representation Letter Resource Evaluation

Regarding the evaluation of our Company's oil and gas resources effective May 31, 2014 (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. defmition 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.

Best regards,

Mark Jarvis
CEO, Shoal Point Energy

EXHIBIT E

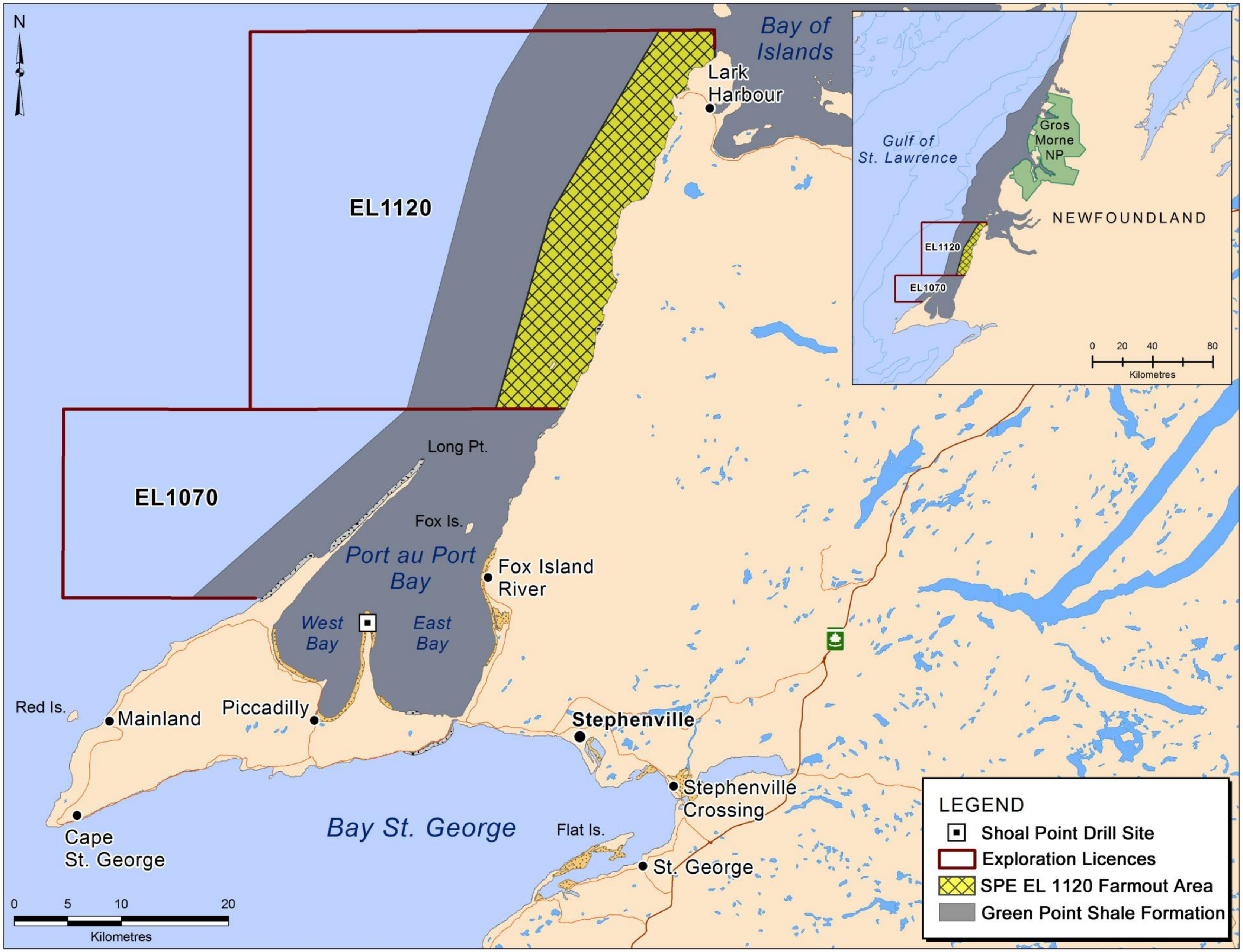
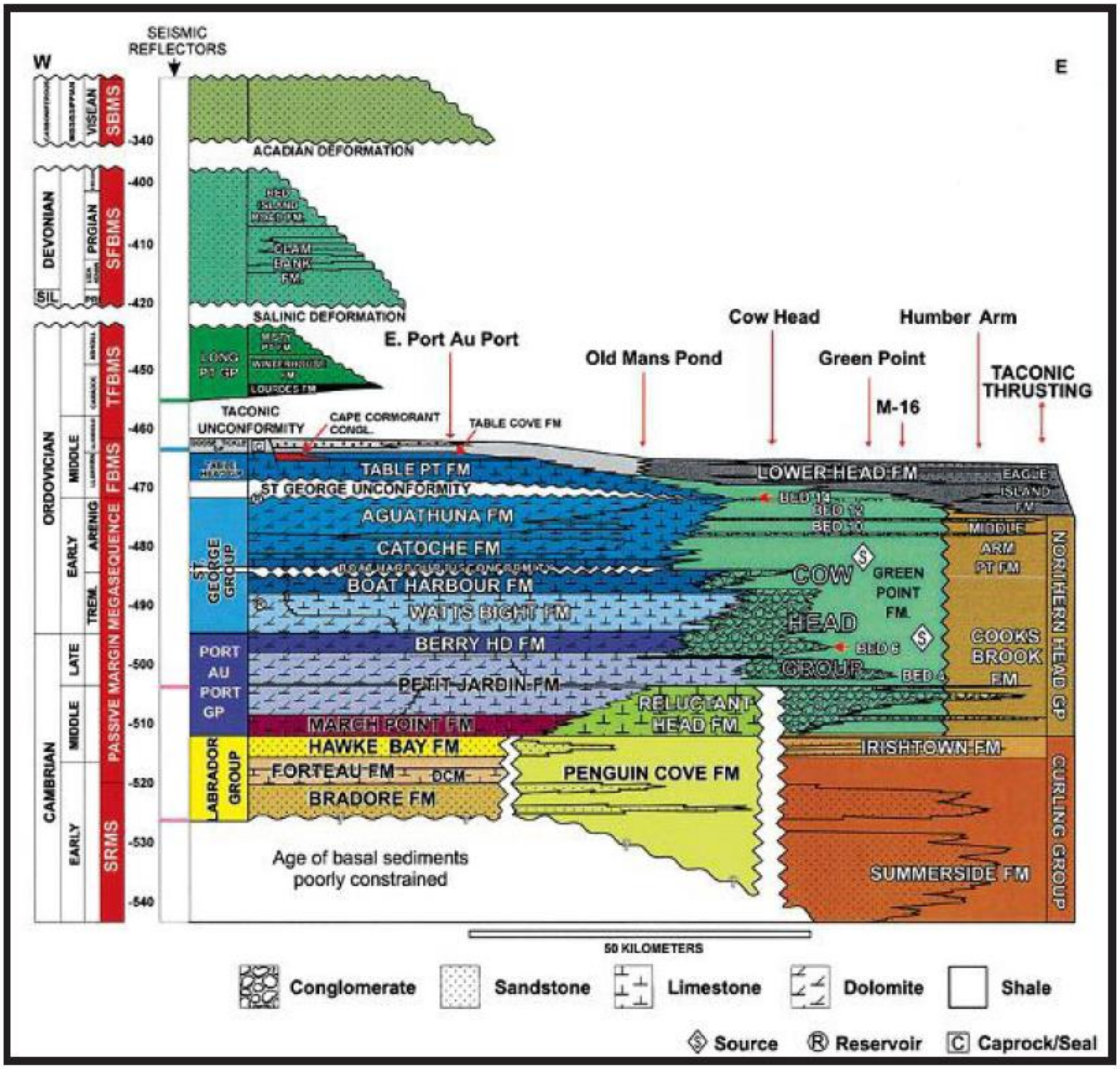
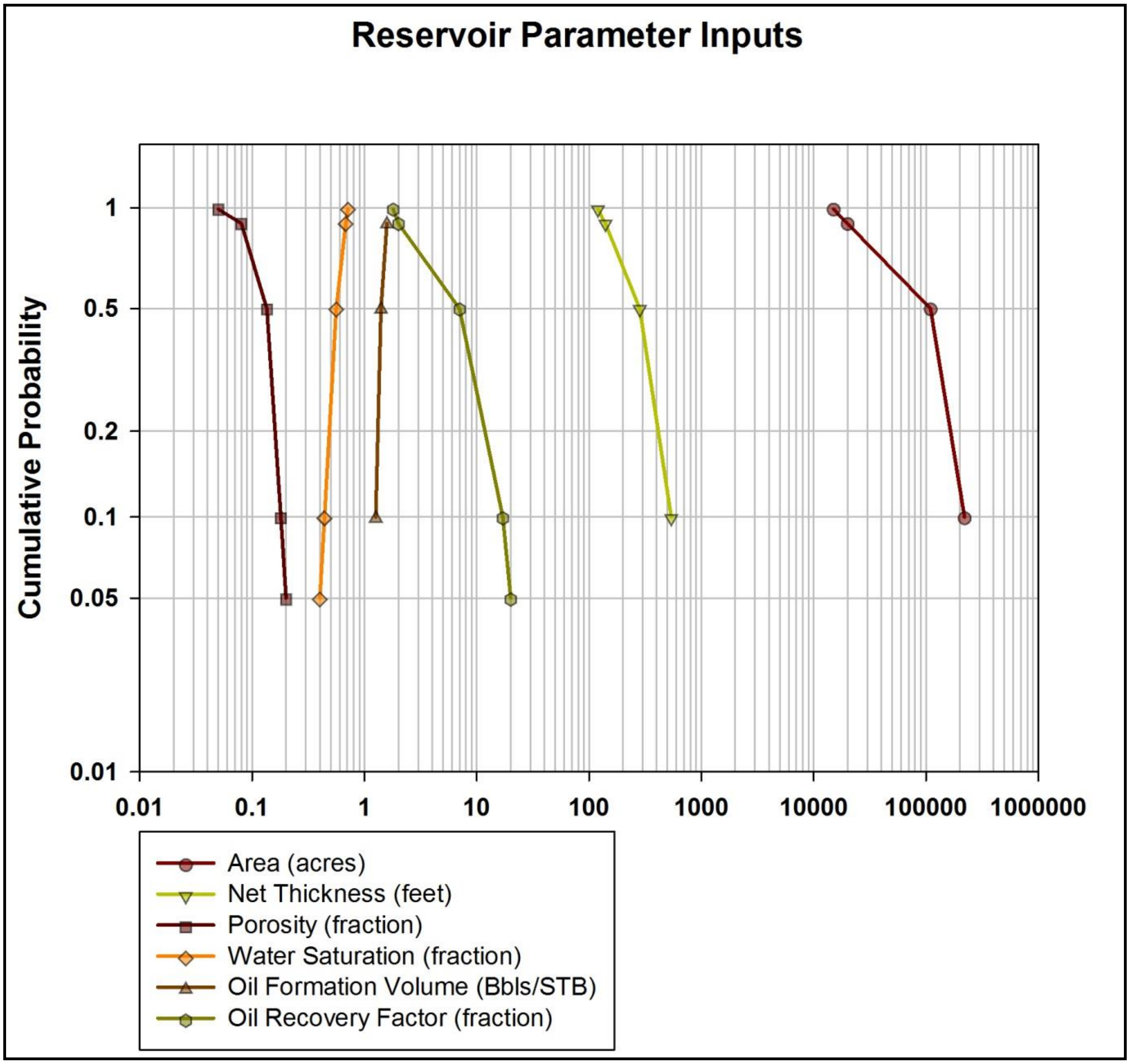

N
Bay of Islands
Lark Harbour
EL1120
EL1070
Long Pt.
Fox Is.
Port au Port Bay
Fox Island River
West Bay
East Bay
Red Is.
Mainland
Piccadilly
Stephenville
Stephenville Crossing
Cape St. George
Bay St. George
Flat Is.
St. George
0 5 10 20
Kilometres
Gulf of St. Lawrence
Gros Morne NP
NEWFOUNDLAND
EL1120
EL1070
0 20 40 80
Kilometres
LEGEND
Shoal Point Drill Site
Exploration Licences
SPE EL 1120 Farmout Area
Green Point Shale Formation

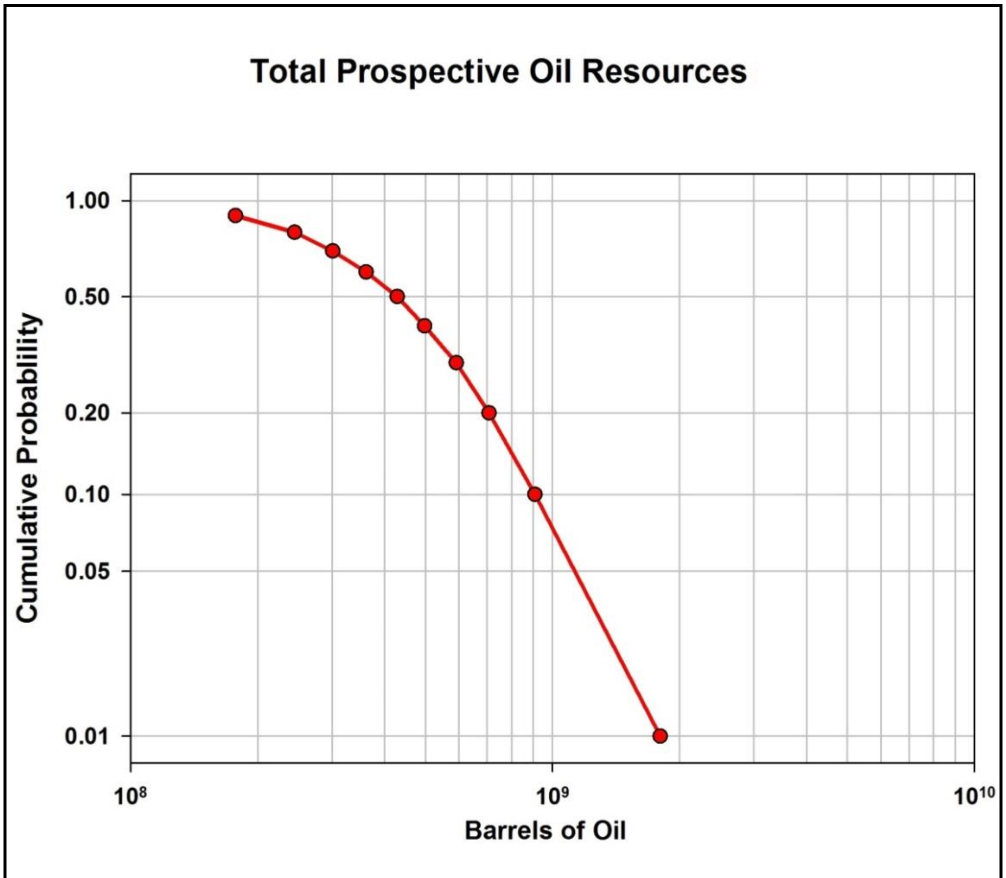
EXHIBIT F



SEISMIC REFLECTORS
W
E
ACADIAN DEFORMATION
SALINIC DEFORMATION
E. Port Au Port
Old Mans Pond
Cow Head
Green Point
Humber Arm
M-16
TACONIC THRUSTING
TACONIC UNCONFORMITY
CAPE CORMORANT CONGL.
TABLE COVE FM
TABLE PT FM
ST GEORGE UNCONFORMITY
AGUATHUNA FM
CATOCHE FM
BOAT HARBOUR FM
WATTS BIGHT FM
BERRY HD FM
PETIT JARDIN FM
MARCH POINT FM
HAWKE BAY FM
FORTEAU FM
BRADORE FM
PENGUIN COVE FM
RELUCTANT HEAD FM
LOWER HEAD FM
COW HEAD GROUP
GREEN POINT FM
IRISHTOWN FM
SUMMERSIDE FM
COOKS BROOK FM
MIDDLE ARM PT FM
NORTHERN HEAD GP
CURLING GROUP
ST. GEORGE GROUP
PORT AU PORT GP
LABRADOR GROUP
Age of basal sediments poorly constrained
50 KILOMETERS
Conglomerate
Sandstone
Limestone
Dolomite
Shale
Source
Reservoir
Caprock/Seal

Exhibit G: Probability Distribution Functions




Total Prospective Oil Resources
1.00
0.50
0.20
0.10
0.05
0.01
Cumulative Probability
10^8
10^9
10^{10}
Barrels of Oil

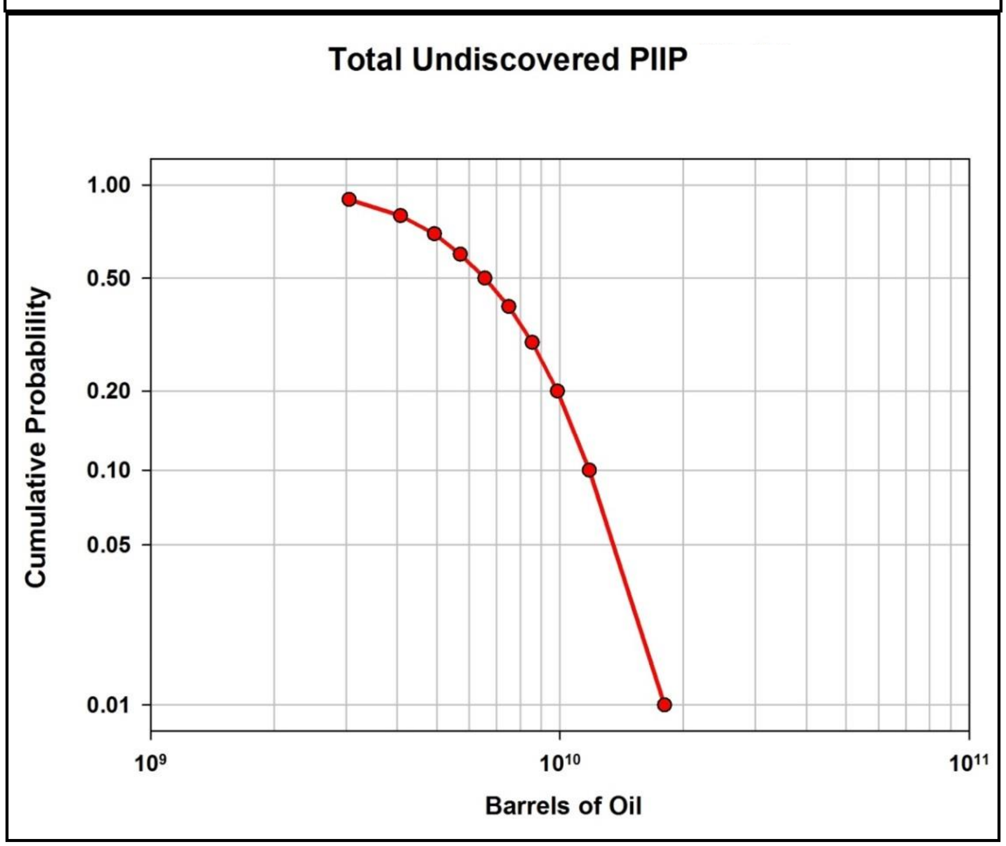

Total Undiscovered PIIP
1.00
0.50
0.20
0.10
0.05
0.01
Cumulative Probability
10^9
10^{10}
10^{11}
Barrels of Oil

Table 5.1a

WESTERN CANADA*
AVERAGE PRICES OF CRUDE OIL & NATURAL GAS

1947 - 1990

EXHIBIT H

	Crude Oil Average Wellhead Price Dollars Per Cubic Metre	Natural Gas Average Wellhead/Plant Gate Price Dollars Per Thou. Cubic Metres	Consumer Price Index Numbers** 1947 = 100
1947	16.00	2.40	100.00
1948	18.91	2.32	114.00
1949	17.75	2.24	117.60
1950	18.15	2.08	121.10
1951	15.62	2.19	133.90
1952	14.67	3.33	137.30
1953	15.50	3.30	135.90
1954	15.91	3.28	136.70
1955	14.78	3.32	136.90
1956	14.88	3.41	138.90
1957	15.77	3.54	143.40
1958	15.27	3.38	147.30
1959	14.60	3.18	148.70
1960	14.48	3.42	150.70
1961	14.56	4.06	152.10
1962	13.98	4.31	154.00
1963	14.90	4.73	156.60
1964	15.34	4.92	159.40
1965	15.38	4.87	163.30
1966	15.42	5.08	169.40
1967	15.40	5.12	175.30
1968	15.43	5.10	182.60
1969	15.15	5.03	190.90
1970	15.56	5.26	197.20
1971	17.22	5.22	202.80
1972	17.36	5.43	212.60
1973	21.44	5.99	228.60
1974	35.87	9.49	253.50
1975	45.09	19.26	280.90
1976	52.57	31.31	302.00
1977	63.22	41.70	326.20
1978	75.70	48.36	355.40
1979	81.95	54.99	387.80
1980	97.00	75.48	427.10
1981	117.10	80.61	480.40
1982	163.06	87.80	532.30
1983	197.92	93.23	563.40
1984	208.37	96.79	587.70
1985	220.98	93.57	611.00
1986	113.91	73.47	636.00
1987	138.26	58.55	663.90
1988	101.08	52.78	690.80
1989	121.88	53.77	725.40
1990	148.86	54.32	760.40

*Includes Alberta, British Columbia, Manitoba, Saskatchewan & Territories.

**Converted for illustrative purposes from base period 1971 = 100.

November 2006

WESTERN CANADA*
AVERAGE PRICES OF CRUDE OIL & NATURAL GAS

1991 - 2012

EXHIBIT H

	Crude Oil Average Wellhead Price Dollars Per Cubic Metre	Natural Gas Average Wellhead/Plant Gate Price Dollars Per Thou. Cubic Metres	Consumer Price Index Numbers** 1947 = 100
1991	120.78	48.28	803.00
1992	123.00	47.99	815.10
1993	113.15	58.38	829.77
1994	119.70	66.08	831.43
1995	132.35	48.85	848.89
1996	160.77	56.74	862.47
1997	143.94	68.44	876.27
1998	100.07	67.70	884.16
1999	150.24	87.41	899.19
2000	233.83	164.61	923.60
2001	186.17	196.87	947.20
2002	209.23	137.15	963.00
2003	223.33	221.96	989.96
2004	260.41	226.64	1 008.58
2005	324.64	298.56	1 030.74
2006	352.87	237.34	1 050.97
2007	375.88	234.37	1 074.09
2008	557.11	282.10	1 098.80
2009	373.76	141.99	1 102.09
2010	439.60	136.40	1 121.93
2011	524.74	124.43	1 154.47
2012	490.05	84.71	1 184.48

*Includes Alberta, British Columbia, Manitoba, Saskatchewan & Territories.

**Converted for illustrative purposes from base period 1971 = 100.

Table 5.2a

EXHIBIT H

AVERAGE PRICES OF CRUDE OIL & NATURAL GAS BY PROVINCE

1951 - 2012

	Crude Oil (1)				Natural Gas (2)		
	British Columbia	Alberta	Sask	Manitoba	British Columbia	Alberta	Sask
1951	-	15.87	7.37	13.48	-	2.17	3.54
1952	-	14.92	7.59	10.69	-	3.32	3.72
1953	-	15.82	7.85	15.91	-	3.29	3.68
1954	-	16.37	8.86	16.30	1.50	3.28	3.56
1955	10.87	15.29	9.72	14.45	1.80	3.32	3.28
1956	12.67	15.55	10.43	14.59	3.00	3.42	3.33
1957	12.72	16.41	13.25	15.74	2.23	3.63	3.28
1958	12.37	15.88	13.49	15.40	2.14	3.83	2.74
1959	11.47	15.12	12.92	14.46	2.19	3.39	3.47
1960	11.10	15.09	12.45	14.12	3.20	3.46	3.55
1961	11.78	14.89	12.96	14.23	3.25	4.29	3.56
1962	10.67	14.23	13.77	15.22	3.34	4.51	3.67
1963	11.46	15.53	14.06	15.32	3.60	4.94	3.76
1964	11.70	16.07	14.34	15.24	3.64	5.17	3.77
1965	12.46	16.12	14.32	15.61	3.71	5.10	4.04
1966	12.90	16.18	14.25	15.74	3.82	5.33	4.48
1967	13.61	16.00	14.35	15.74	3.50	5.49	4.82
1968	13.64	16.08	14.12	15.78	3.41	5.51	4.70
1969	13.93	15.61	14.07	15.84	3.37	5.46	3.89
1970	14.49	16.07	14.00	15.82	3.34	5.69	4.60
1971	15.87	17.78	15.41	17.34	3.39	5.60	4.60
1972	15.45	17.89	15.40	17.46	3.59	5.89	4.56
1973	19.25	21.91	19.22	21.23	3.57	6.62	4.81
1974	33.06	36.34	33.66	36.02	5.43	10.46	5.22
1975	38.27	45.64	43.09	44.84	7.14	21.79	6.01
1976	42.07	53.46	49.73	52.95	11.43	35.34	7.33
1977	55.38	64.24	59.07	64.17	20.80	45.69	10.92
1978	66.90	76.78	71.28	76.80	24.39	52.57	15.14
1979	72.61	82.93	77.35	82.97	28.63	59.84	14.63
1980	92.18	97.69	92.22	97.52	31.44	82.51	16.40
1981	115.87	118.17	110.75	118.03	36.98	87.19	16.56
1982	160.82	161.51	175.47	172.68	43.71	94.31	19.07
1983	193.42	200.12	186.88	206.73	45.22	100.39	38.18
1984	207.53	209.96	201.16	213.41	49.94	103.68	50.80
1985	213.64	214.33	204.52	219.38	54.53	99.00	57.63
1986	121.41	117.86	100.28	115.77	45.11	77.74	53.73
1987	144.99	142.03	125.17	139.64	45.08	59.98	64.60
1988	108.56	105.38	84.47	102.26	42.86	54.02	50.54
1989	130.14	125.93	106.36	124.66	48.54	54.77	49.36
1990	151.88	154.61	125.31	155.85	47.51	55.18	54.18
1991	130.91	126.95	95.76	117.04	43.64	48.65	53.12
1992	120.72	128.07	105.94	131.46	41.14	48.68	53.06
1993	118.09	117.36	99.63	122.11	50.05	60.08	52.64
1994	119.02	123.82	108.73	124.99	53.87	68.07	66.57
1995	134.15	136.11	122.56	140.50	40.38	49.99	51.54
1996	166.95	165.56	148.29	173.90	44.13	58.90	51.38
1997	162.11	150.28	126.89	165.10	54.27	70.96	62.62
1998	112.06	105.43	86.16	116.64	55.45	69.70	64.39
1999	159.53	153.66	142.25	166.16	76.65	88.68	96.30
2000	257.92	244.72	209.50	266.20	178.51	162.34	165.99
2001	221.33	198.76	157.52	214.91	189.11	198.39	193.24
2002	227.44	217.63	191.71	230.16	125.44	139.48	139.43
2003	252.80	232.44	203.44	252.57	210.78	224.62	215.00
2004	305.54	278.56	226.75	306.93	216.19	228.84	225.81
2005	397.87	352.57	275.65	402.83	286.20	301.75	285.90
2006	423.45	381.03	305.19	422.50	223.54	240.86	226.53
2007	429.29	405.40	326.72	480.18	228.95	235.66	230.69
2008	596.67	580.12	523.26	608.15	275.87	283.86	274.32
2009	375.87	379.19	365.06	414.05	139.33	142.86	136.59
2010	459.14	450.07	422.29	484.67	130.25	137.98	138.44
2011	564.83	543.55	493.76	582.32	121.66	125.36	125.34
2012	548.02	495.23	475.20	533.10	85.30	84.50	84.60

(1) Average Wellhead Price ($ per M^3)

(2) Average Wellhead/Plant Gate Price ($ per 10^3M^3)

March 2014