



**ANNUAL INFORMATION FORM**  
**For the Year Ended December 31, 2010**

**MARCH 7, 2011**

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## GLOSSARY OF ABBREVIATIONS

|                |  |
|----------------|--|
| <b>AECO-C</b>  | Alberta Energy Company "C" Meter Station of the Nova Pipeline System |
| <b>API</b>     | American Petroleum Institute   |
| <b>Bbl</b>     | Barrels  |
| <b>Bbl/d</b>   | Barrels per day  |
| <b>BOE</b>     | Barrel of oil equivalent   |
| <b>BOE/d</b>   | Barrels of oil equivalent per day                                    |
| <b>GJ</b>      | Gigajoules   |
| <b>GJ/d</b>    | Gigajoules per day   |
| <b>Lt</b>      | Long tons  |
| <b>Lt/d</b>    | Long tons per day  |
| <b>Mbbl</b>    | Thousand barrels   |
| <b>MBOE</b>    | Thousands of barrels of oil equivalent                               |
| <b>Mcf</b>     | Thousand cubic feet  |
| <b>MMcf</b>    | Million cubic feet   |
| <b>MMcf/d</b>  | Million cubic feet per day   |
| <b>MMbtu</b>   | Million British thermal units  |
| <b>MMbtu/d</b> | Million British thermal units per day                                |
| <b>NGLs</b>    | Natural gas liquids  |
| <b>WTI</b>     | West Texas Intermediate  |
| <b>M\$</b>     | Thousands of dollars   |
| <b>MM\$</b>    | Millions of dollars  |

## CONVERSION OF UNITS

|                    |                    |
|--------------------|--------------------|
| <b>1 acre</b>      | 0.4 hectares       |
| <b>2.5 acres</b>   | 1 hectare          |
| <b>1 Bbl</b>       | 0.159 cubic metres |
| <b>6.29 Bbls</b>   | 1 cubic metre      |
| <b>1 foot</b>      | 0.3048 metres      |
| <b>3.281 feet</b>  | 1 metre            |
| <b>1 mcf</b>       | 28.2 cubic metres  |
| <b>0.035 mcf</b>   | 1 cubic metre      |
| <b>1 mile</b>      | 1.61 kilometres    |
| <b>0.62 miles</b>  | 1 kilometre        |
| <b>1 MMBtu</b>     | 1.054 GJ           |
| <b>0.949 MMBtu</b> | 1 GJ               |

In this Annual Information Form where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Unless otherwise specified, references to oil include oil and NGLs. NGLs include condensate, propane, butane and ethane.

## CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

## FORWARD-LOOKING STATEMENTS

This Annual Information Form and the documents incorporated by reference herein contain forward looking statements. These statements relate to future events or Celtic's future performance. All statements other than statements of historical fact may be forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms

or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In addition, this Annual Information Form and the documents incorporated by reference herein may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this Annual Information Form and the documents incorporated by reference herein include, but are not limited to, statements with respect to:

- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- plans for facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of Celtic;
- timing of receipt of regulatory approvals;
- effect of production increases on operating costs per BOE;
- ability to lower cost structure in certain projects of Celtic;
- growth expectations within Celtic;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Celtic;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of Celtic's oil and natural gas properties;
- Celtic's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of Canadian federal and provincial governmental regulation on Celtic relative to other oil and gas issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- the quantity and quality of the oil and natural gas reserves;
- projections of commodity prices and costs;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

Although Celtic believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Celtic cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither Celtic nor any other person assumes responsibility for the outcome of the forward-looking statements. Many of the risks and other factors are beyond Celtic's control, which could cause results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein. The risks and other factors include, but are not limited to:

- general economic conditions in Canada, the United States and globally including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas;
- liabilities inherent in oil and natural gas operations;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;

- failure to realize anticipated benefits of acquisitions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions or reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- right to surface access;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "Risk Factors" in this Annual Information Form and the other risk factors identified in the other documents incorporated herein by reference.

These factors should not be considered as exhaustive. Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this Annual Information Form, Celtic has made assumptions regarding: future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; current technology; cash flow; commodity prices; production rates; timing and amount of capital expenditures; marketability of oil and natural gas; royalty rates; effects of regulation by governmental agencies; future operating costs and the Corporation's ability to obtain financing on acceptable terms. In addition, forward-looking statements in documents incorporated by reference herein may be based on additional assumptions as disclosed in such documents. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Celtic's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

**The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Celtic is not under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.**

## CORPORATE STRUCTURE

### Name, Address and Incorporation

Celtic Exploration Ltd., (the "**Corporation**" or "**Celtic**"), was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") on April 16, 2002 as Desco Exploration Ltd. On September 30, 2002, the Corporation filed Articles of Amendment to change its name from "Desco Exploration Ltd." to "Celtic Exploration Ltd."

The Corporation does not have any subsidiaries.

The head office of Celtic is located at Suite 500, 505 – 3<sup>rd</sup> Street S.W., Calgary, Alberta, T2P 3E6 and the registered office is located at 1900, 520 - 3<sup>rd</sup> Avenue S.W., Calgary, Alberta T2P 0R3.

## GENERAL DEVELOPMENT OF THE BUSINESS

### History of the Corporation

#### 2008

In April 2008, Celtic completed an equity financing by way of a short form prospectus of 2,875,000 common shares in the capital of the Corporation ("**Common Shares**") at a price of \$15.00 per share for

gross proceeds of \$43.1 million. The proceeds were used to finance Celtic's development, exploration and acquisition activities.

In April 2008, Celtic completed the acquisition of certain liquids-rich natural gas assets located in the Kaybob South area of Alberta. The effective date of the acquisition was January 1, 2008 and the purchase price, after adjustments, was \$45.0 million.

## **2009**

In April 2009, Celtic completed an equity financing by way of a short form prospectus of 2,750,000 Common Shares at a price of \$13.25 per share for gross proceeds of \$36.4 million. The proceeds were used to finance Celtic's on-going capital expenditure program.

## **2010**

In March 2010, Celtic completed the disposition of certain oil and gas assets located in the Swan Hills area of Alberta for proceeds of \$53.25 million, prior to adjustments.

In May 2010, Celtic completed a two-for-one stock split of the issued and outstanding Common Shares in the capital of the Corporation.

In November 2010, Celtic approved a capital expenditure budget for 2011 of \$180.0 million and announced that the Corporation expected to participate in the drilling of approximately 38 to 40 (36 to 38) net wells during 2011, of which over 90% would be horizontal wells. Approximately 40% to 45% of the wells expected to be drilled in 2011 were planned for the Kaybob area of Alberta. The remaining budgeted wells were expected to be drilled in west central Alberta, where Celtic has been active on various new exploration plays, including in the Resthaven, Lator and Karr areas.

## **Activity During Current Financial Year**

In January 2011, Celtic continued with its exploration activity at Resthaven, Lator and Karr areas in west central Alberta in respect of its Triassic Montney rights therein. Celtic also continued with its follow-up drilling on its Devonian Duvernay formation shale gas rights in the Kaybob area Alberta, as well as with the Montney and Bluesky zone development program in the Kaybob area. In addition, Celtic discovered a new Montney pool in the Fir area, Alberta. Celtic also acquired interests in certain production and acreage in the Inga area of British Columbia and participated in a successful horizontal Doig well on that acreage.

## **General**

Celtic is engaged in the exploration for, and the development and production of, oil and natural gas. Celtic's current activities are primarily focused in the Greater Kaybob South area and in the Resthaven area in west central Alberta. Other operating areas include the Princess, Bantry, Michichi, Richdale and Drumheller areas in Southern Alberta, in east central Alberta in the Ashmont and Figure Lake areas, in west central Alberta in the Fox Creek, Pedley, Karr, Lator and the Pine Creek areas and in northern Alberta, in the Utikuma Lake area.

## **Stated Business Objective**

The business plan of Celtic is to create sustainable and profitable growth as a participant in the oil and gas industry in Western Canada. To accomplish this, Celtic has been and will continue to pursue an integrated two-pronged growth strategy. On the one hand, Celtic will continue to identify and acquire strategic acquisitions of oil and natural gas properties where it believes further exploitation, development and exploration opportunities exist. In addition, Celtic implements a full cycle exploration program. The Corporation therefore pursues exploration and development drilling together with focused acquisitions both within its existing geographical project areas in the Western Canada Sedimentary Basin and in other areas of Alberta, Saskatchewan and British Columbia which present opportunities which are of interest to its management. Commencing in 2010, and continuing into 2011, this growth strategy has been

supplemented by the disposition of certain non-core assets. Since commencing active oil and gas operations in the fall of 2002, the Corporation has successfully adhered to its two-pronged growth strategy. The Corporation has completed a number of corporate and asset acquisitions and subsequently has actively carried out exploitation and development drilling operations to further enhance the value of the acquired assets. At the same time, the Corporation has accumulated assets through its full cycle exploration program including conducting seismic operations, acquiring land and drilling exploration wells.

Celtic plans to pursue the internal and external generation of exploration plays that have low, medium and high risk and multi-zone hydrocarbon potential and plans to maintain a balance between exploration, exploitation and development drilling for oil and gas reserves over the course of the next five years, although management of Celtic will also consider asset and corporate acquisition opportunities that meet its business parameters. While Celtic believes that it will have the skills and resources necessary to achieve its stated objectives, participation in the exploration for and development of oil and natural gas has a number of inherent risks.

Management of Celtic has extensive industry experience in producing areas of Western Canada in addition to its knowledge of its existing properties and management will have the capability to expand the scope of Celtic's activities as opportunities arise.

In addition to specific acquisition criteria including risk profile, technical upside, reserve life and asset quality that will be evaluated by the management of Celtic, in circumstances where Celtic seeks to acquire assets with proven and probable reserves, prior to the investment decision being finalized, Celtic may obtain an independent engineering report (whether from the vendor of such assets or otherwise) relating to such proven and probable reserves.

### **Corporate Strategy**

Celtic's strategy is to focus on acquisitions of oil and gas assets, to develop a broad inventory of both exploration and development opportunities to mitigate risk on capital investment, to augment acquisition opportunities with drilling activity and to increase critical mass and investigate opportunities to establish new core areas.

### **Business Risks**

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. There is substantial risk that the manpower and capital employed may not result in the finding of new reserves in economic quantities. There is a risk that the sale of Celtic's reserves may be delayed indefinitely due to processing constraints, lack of pipeline capacity or lack of markets. The price Celtic receives for its oil and gas production fluctuates continuously and, for the most part, is beyond our control. Celtic is also subject to the risks associated with owning oil and gas properties, including environmental risks such as the pollution of air, land and water. In all areas of the business, Celtic competes against entities that may have greater technical and financial resources. Celtic's growth is dependent upon external sources of financing which may not be available on acceptable terms.

Celtic mitigates these risks by hiring highly qualified personnel, either directly as employees or indirectly when contracting for services. Celtic's philosophy of focusing in a limited number of geographical areas allows it to develop a high level of technical and managerial expertise in each area. To control the cost and pace of development, Celtic acquires high working interests in each prospect and operates wherever possible. Celtic may enter into commodity price and interest rate hedging strategies to add a degree of certainty to cash flow. The Corporation diversifies its oil and gas market portfolio among various marketers and among a variety of contracts with respect to pricing and term. In the field, Celtic adheres to sound operational standards, which meet or exceed recognized levels. Finally, all levels of the Corporation's operations are adequately insured. (See "Risk Factors").

### **Seasonal Considerations**

Certain properties in the Greater Kaybob area of west central Alberta are accessible only during winter months. The majority of the Corporation's properties are accessible year round, except during spring

break-up. Major facilities through which Celtic's production is processed may temporarily be shut down for a short period of time during the year to conduct repair and maintenance operations.

### Future Commitments

The Corporation may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, currency exchange and interest rates, in order to secure a certain amount of cash flow to protect a desired level of capital spending.

The following is a summary of NYMEX WTI light sweet oil fixed price contracts in effect:

| Daily Quantity     | Remaining term of contract      | Fixed price per Bbl |
|--------------------|---------------------------------|---------------------|
| 1,000 Bbls per day | January 1 to December 31, 2011  | CA\$90.00           |
| 1,000 Bbls per day | February 1 to December 31, 2011 | CA\$91.80           |

The following is a summary of interest rate swap contracts that settle based on the floating Canadian Dollar Banker Acceptance CDOR rate, in effect as at December 31, 2010:

| Amount           | Remaining term of contract  | Fixed interest rate |
|------------------|-----------------------------|---------------------|
| CA\$ 100,000,000 | January 1 to April 21, 2011 | 2.07%               |

### Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. As at December 31, 2010 Celtic recorded a provision on its balance sheet of \$9.9 million for asset retirement obligations for future site restoration, reclamation and abandonment costs. The Corporation maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Corporation also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of Celtic will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Celtic's financial condition, results of operations or prospects. See "*INDUSTRY CONDITIONS - Environmental Regulation*".

### Employees

At December 31, 2010, the Corporation had 40 employees at the head office and, at the locations of the Corporation's field operations, the Corporation had 16 employees.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

### Petroleum and Natural Gas Reserves

Sproule Associates Limited ("**Sproule**"), independent petroleum engineers of Calgary, Alberta, prepared a report entitled "Evaluation of the P&NG Reserves of Celtic Exploration Ltd. (As of December 31, 2010)" (the "**Sproule Report**"), effective December 31, 2010 and dated February 3, 2011, evaluating the proved and probable crude oil, natural gas and NGL reserves attributable to Celtic's interest in 100% of its properties and the present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. The reserves information was prepared and is presented in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

In preparing the Sproule Report, Sproule obtained information from Celtic, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule as represented.

The following tables, based on the Sproule Report, show the estimated share of Celtic's oil, natural gas and NGL reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast price and cost assumptions. **All evaluations of the present worth of estimated future net revenue in the Sproule Report are stated after provision for estimated future capital expenditures and well abandonment and disconnect costs, both before and after income taxes, but prior to indirect costs and surface lease reclamation costs or equipment salvage values and do not necessarily represent the fair market value of the reserves.**

Throughout the following summary tables differences may arise due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

- Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2010 pricing assumptions
- Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the Sproule Report are attached as Appendix C hereto.

The following table summarizes Celtic's oil and gas reserves as of December 31, 2010 based on forecast price and cost assumptions.

| SUMMARY OF OIL AND GAS RESERVES   |                      |                |               |              |                            |                |                 |              |              |              |                     |                |
|-----------------------------------|----------------------|----------------|---------------|--------------|----------------------------|----------------|-----------------|--------------|--------------|--------------|---------------------|----------------|
| as of December 31, 2010           |                      |                |               |              |                            |                |                 |              |              |              |                     |                |
| FORECAST PRICES AND COSTS         |                      |                |               |              |                            |                |                 |              |              |              |                     |                |
| RESERVES                          |                      |                |               |              |                            |                |                 |              |              |              |                     |                |
| RESERVES CATEGORY                 | LIGHT AND MEDIUM OIL |                | HEAVY OIL     |              | NATURAL GAS <sup>(1)</sup> |                | COALBED METHANE |              | SHALE GAS    |              | NATURAL GAS LIQUIDS |                |
|                                   | Gross (Mbbbl)        | Net (Mbbbl)    | Gross (Mbbbl) | Net (Mbbbl)  | Gross (MMcf)               | Net (MMcf)     | Gross (MMcf)    | Net (MMcf)   | Gross (MMcf) | Net (MMcf)   | Gross (Mbbbl)       | Net (Mbbbl)    |
| <b>PROVED</b>                     |                      |                |               |              |                            |                |                 |              |              |              |                     |                |
| Developed Producing               | 1,375.2              | 1,116.7        | 361.1         | 344.4        | 107,250                    | 98,897         | 320             | 324          | 0            | 0            | 4,590.1             | 3,118.9        |
| Developed Non-Producing           | 186.0                | 164.0          | 9.9           | 9.9          | 10,552                     | 9,343          | 755             | 655          | 330          | 310          | 546.7               | 401.5          |
| Undeveloped                       | 181.2                | 149.4          | 0.0           | 0.0          | 52,057                     | 48,178         | 1,497           | 1,256        | 531          | 505          | 2,199.6             | 1,760.7        |
| <b>TOTAL PROVED</b>               | <b>1,742.4</b>       | <b>1,430.1</b> | <b>371.1</b>  | <b>354.3</b> | <b>169,859</b>             | <b>156,418</b> | <b>2,572</b>    | <b>2,235</b> | <b>861</b>   | <b>815</b>   | <b>7,336.4</b>      | <b>5,281.1</b> |
| PROBABLE                          | 1,164.8              | 929.4          | 104.2         | 102.9        | 123,671                    | 111,345        | 2,120           | 1,876        | 1,405        | 1,326        | 6,088.2             | 4,273.9        |
| <b>TOTAL PROVED PLUS PROBABLE</b> | <b>2,907.2</b>       | <b>2,359.5</b> | <b>475.3</b>  | <b>457.2</b> | <b>293,529</b>             | <b>267,763</b> | <b>4,692</b>    | <b>4,111</b> | <b>2,266</b> | <b>2,141</b> | <b>13,424.6</b>     | <b>9,555.0</b> |

**Note:**

(1) Natural gas volumes include associated, non-associated and solution gas.

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Celtic's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2010.

| <b>SUMMARY OF NET PRESENT VALUES OF<br/>FUTURE NET REVENUE<br/>as of December 31, 2010</b> |   |                    |                     |                     |                     |  |                    |                     |                     |                     |  |
|--|---|--------------------|---------------------|---------------------|---------------------|--|--------------------|---------------------|---------------------|---------------------|--|
| <b>FORECAST PRICES AND COSTS</b>   |   |                    |                     |                     |                     |  |                    |                     |                     |                     |  |
| <b>Reserves<br/>Category</b>   | <b>BEFORE INCOME TAXES<br/>DISCOUNTED AT (%/year)</b> |                    |                     |                     |                     | <b>AFTER INCOME TAXES<br/>DISCOUNTED AT (%/year)</b> |                    |                     |                     |                     | <b>UNIT<br/>VALUE<br/>BEFORE<br/>INCOME<br/>TAX<br/>DISCOUN-<br/>TED AT<br/>10%/year</b> |
|  | <b>0<br/>(M\$)</b>                                    | <b>5<br/>(M\$)</b> | <b>10<br/>(M\$)</b> | <b>15<br/>(M\$)</b> | <b>20<br/>(M\$)</b> | <b>0<br/>(M\$)</b>                                   | <b>5<br/>(M\$)</b> | <b>10<br/>(M\$)</b> | <b>15<br/>(M\$)</b> | <b>20<br/>(M\$)</b> | <b>\$/BOE</b>  |
| <b>Proved</b>  |   |                    |                     |                     |                     |  |                    |                     |                     |                     |  |
| Developed<br>Producing   | 611,593   | 492,560            | 417,037             | 364,529             | 325,768             | 571,867  | 465,578            | 397,629             | 349,990             | 314,539             | 19.75  |
| Developed<br>Non-<br>Producing   | 61,397  | 51,291             | 44,015              | 38,542              | 34,281              | 46,040   | 38,551             | 33,201              | 29,202              | 26,102              | 19.19  |
| Un-<br>developed   | 209,767   | 149,213            | 110,277             | 83,249              | 63,487              | 157,143  | 108,659            | 77,370              | 55,641              | 39,779              | 10.78  |
| <b>Total Proved</b>  | <b>882,757</b>  | <b>693,063</b>     | <b>571,329</b>      | <b>486,321</b>      | <b>423,535</b>      | <b>775,051</b>                                       | <b>612,788</b>     | <b>508,200</b>      | <b>434,833</b>      | <b>380,420</b>      | <b>16.98</b>   |
| Probable   | 796,790   | 501,413            | 359,422             | 276,414             | 221,944             | 596,943  | 373,961            | 266,417             | 203,471             | 162,171             | 14.73  |
| <b>Total Proved<br/>Plus<br/>Probable</b>  | <b>1,679,547</b>                                      | <b>1,194,476</b>   | <b>930,750</b>      | <b>762,735</b>      | <b>645,479</b>      | <b>1,371,993</b>                                     | <b>986,749</b>     | <b>774,617</b>      | <b>638,305</b>      | <b>542,591</b>      | <b>16.04</b>   |

| TOTAL FUTURE NET REVENUE<br>(UNDISCOUNTED)<br>as of December 31, 2010 |                  |                    |                             |                                    |   |  |                          |   |
|---|------------------|--------------------|-----------------------------|------------------------------------|---|--|--------------------------|---|
| FORECAST PRICES AND COSTS   |                  |                    |                             |                                    |   |  |                          |   |
| RESERVES<br>CATEGORY  | REVENUE<br>(M\$) | ROYALTIES<br>(M\$) | OPERATING<br>COSTS<br>(M\$) | DEVELOP-<br>MENT<br>COSTS<br>(M\$) | ABANDON-<br>MENT AND<br>OTHER<br>COSTS<br>(M\$) | FUTURE<br>NET<br>REVENUE<br>BEFORE<br>INCOME<br>TAXES<br>(M\$) | INCOME<br>TAXES<br>(M\$) | FUTURE<br>NET<br>REVENUE<br>AFTER<br>INCOME<br>TAXES<br>(M\$) |
| Proved<br>Reserves  | 1,871,332        | 287,416            | 554,565                     | 135,431                            | 11,163  | 882,757  | 107,707                  | 775,051   |
| Proved Plus<br>Probable<br>Reserves                                   | 3,478,186        | 561,848            | 1,008,044                   | 214,394                            | 14,354  | 1,679,547  | 307,554                  | 1,371,993   |

**Note:**

(1) Future development costs include the full capital for drilling. Drilling royalty credits of \$4,114,000 for the proved case and \$4,674,000 for the proved plus probable case have been included in revenue in the above table.

| FUTURE NET REVENUE<br>BY PRODUCTION GROUP<br>as of December 31, 2010 |  |   |   |
|--|--|---|---|
| FORECAST PRICES AND COSTS  |  |   |   |
| RESERVES<br>CATEGORY   | PRODUCTION GROUP   | FUTURE NET<br>REVENUE<br>BEFORE INCOME<br>TAXES<br>(discounted at<br>10%/Year)<br>(M\$) | UNIT VALUE<br>BEFORE<br>INCOME TAXES<br>(discounted at<br>10%/Year)<br>(\$/BOE) |
| <b>Proved Reserves</b>   | Light and Medium Oil (including solution gas and associated by-products) | 46,367  | 27.00   |
|  | Heavy Oil (including solution gas and associated by-products)            | 9,638   | 26.95   |
|  | Natural Gas (including associated by-products) <sup>(1)</sup>            | 510,240   | 16.46   |
|  | Coalbed Methane (including associated by-products)                       | 3,295   | 8.84  |
|  | Shale Gas (including associated by-products)                             | 1,789   | 8.92  |
|  | Total  | 571,329   |   |
| <b>Proved Plus<br/>Probable Reserves</b>                             | Light and Medium Oil (including solution gas and associated by-products) | 63,544  | 22.15   |
|  | Heavy Oil (including solution gas and associated by-products)            | 11,667  | 25.27   |
|  | Natural Gas (including associated by-products) <sup>(1)</sup>            | 845,328   | 15.80   |
|  | Coalbed Methane (including associated by-products)                       | 5,792   | 8.45  |
|  | Shale Gas (including associated by-products)                             | 4,420   | 8.39  |
|  | Total  | 930,751   |   |

**Note:**

(1) Includes corporate capital gas cost allowance.

**PRICING ASSUMPTIONS**

**Forecast Prices and Costs - December 31, 2010**

Sproule employed the following pricing, exchange rate and inflation rate assumptions in estimating Celtic's reserves data using forecast prices and costs as of December 31, 2010.

**FORECAST PRICES USED IN PREPARING RESERVES DATA**

**Sproule Associates Limited**

**Price Forecast**

**Effective December 31, 2010**

| Year              | Light Oil                          |  | Heavy & Medium Oil                         |  | Natural Gas Liquids          |                              |                                    |
|-------------------|------------------------------------|--|--|--|------------------------------|------------------------------|------------------------------------|
|                   | WTI Cushing Oklahoma (\$US/Bbl)    | Edmonton Par Price 40° API (\$Cdn/Bbl) | Hardisty Lloyd Blend 20.5° API (\$Cdn/Bbl) | Hardisty Bow River 24.9° API (\$Cdn/Bbl) | Edmonton Propane (\$Cdn/Bbl) | Edmonton Butanes (\$Cdn/Bbl) | Edmonton Pentanes Plus (\$Cdn/Bbl) |
| <b>Historical</b> |                                    |  |  |  |                              |                              |                                    |
| 2005              | 56.46                              | 69.29                                  | 42.79                                      | 45.62                                    | 38.54                        | 45.20                        | 69.13                              |
| 2006              | 66.09                              | 73.30                                  | 50.30                                      | 51.54                                    | 44.09                        | 59.32                        | 75.03                              |
| 2007              | 72.27                              | 77.06                                  | 51.93                                      | 53.16                                    | 49.53                        | 63.71                        | 77.33                              |
| 2008              | 99.59                              | 102.85                                 | 82.58                                      | 83.85                                    | 58.80                        | 75.09                        | 104.70                             |
| 2009              | 61.63                              | 66.20                                  | 58.49                                      | 59.71                                    | 38.89                        | 47.07                        | 68.13                              |
| 2010              | 79.43                              | 77.81                                  | 67.16                                      | 68.26                                    | 46.98                        | 57.04                        | 84.21                              |
| <b>Forecast</b>   |                                    |  |  |  |                              |                              |                                    |
| 2011              | 88.40                              | 93.08                                  | 80.04                                      | 81.91                                    | 55.20                        | 62.44                        | 95.32                              |
| 2012              | 89.14                              | 93.65                                  | 80.71                                      | 82.59                                    | 55.66                        | 62.95                        | 96.11                              |
| 2013              | 88.77                              | 93.43                                  | 78.48                                      | 81.28                                    | 55.41                        | 62.67                        | 95.68                              |
| 2014              | 88.88                              | 93.54                                  | 76.70                                      | 80.44                                    | 55.47                        | 62.75                        | 95.79                              |
| 2015              | 90.22                              | 94.95                                  | 77.86                                      | 81.66                                    | 56.31                        | 63.69                        | 97.24                              |
| 2016              | 91.57                              | 96.38                                  | 79.03                                      | 82.89                                    | 57.16                        | 64.65                        | 98.71                              |
| 2017              | 92.94                              | 97.84                                  | 80.23                                      | 84.14                                    | 58.02                        | 65.63                        | 100.20                             |
| 2018              | 94.34                              | 99.32                                  | 81.44                                      | 85.41                                    | 58.90                        | 66.62                        | 101.71                             |
| 2019              | 95.75                              | 100.81                                 | 82.67                                      | 86.70                                    | 59.79                        | 67.63                        | 103.25                             |
| 2020              | 97.19                              | 102.34                                 | 83.92                                      | 88.01                                    | 60.69                        | 68.65                        | 104.81                             |
| Thereafter        | Escalation rate of 1.5% thereafter |  |  |  |                              |                              |                                    |

| Year              | Natural Gas   |                                   |                                     |                                 |                              | Operating Cost Inflation Rate (%/Yr) | Exchange Rate (\$US/\$Cdn) |
|-------------------|---|-----------------------------------|-------------------------------------|---------------------------------|------------------------------|--------------------------------------|----------------------------|
|                   | Alberta Gas Reference Price Plantgate (\$Cdn/MMbtu) | Alberta AECO-C Spot (\$Cdn/MMbtu) | Aggregator Intra-Alta (\$Cdn/MMbtu) | Alliance Pipeline (\$Cdn/MMbtu) | Henry Hub Price (\$US/MMbtu) |                                      |                            |
| <b>Historical</b> |   |                                   |                                     |                                 |                              |                                      |                            |
| 2005              | 8.30  | 8.58                              | 8.46                                | 8.45                            | 8.62                         | 1.3                                  | 0.826                      |
| 2006              | 6.56  | 7.16                              | 6.57                                | 6.56                            | 7.23                         | 1.5                                  | 0.882                      |
| 2007              | 6.20  | 6.65                              | 6.34                                | 6.04                            | 6.86                         | 2.0                                  | 0.935                      |
| 2008              | 7.88  | 8.15                              | 8.03                                | 7.91                            | 9.04                         | 1.0                                  | 0.943                      |
| 2009              | 3.75  | 4.19                              | 3.69                                | 3.35                            | 4.01                         | 2.0                                  | 0.880                      |
| 2010              | 3.88  | 4.16                              | 3.14                                | 3.37                            | 4.39                         | 1.0                                  | 0.971                      |
| <b>Forecast</b>   |   |                                   |                                     |                                 |                              |                                      |                            |
| 2011              | 3.82  | 4.04                              | 3.34                                | 3.26                            | 4.44                         | 1.5                                  | 0.932                      |
| 2012              | 4.46  | 4.66                              | 4.02                                | 3.98                            | 5.01                         | 1.5                                  | 0.932                      |
| 2013              | 4.82  | 4.99                              | 4.41                                | 4.41                            | 5.32                         | 1.5                                  | 0.932                      |
| 2014              | 6.42  | 6.58                              | 6.05                                | 6.05                            | 6.80                         | 1.5                                  | 0.932                      |
| 2015              | 6.53  | 6.69                              | 6.16                                | 6.16                            | 6.90                         | 1.5                                  | 0.932                      |
| 2016              | 6.68  | 6.80                              | 6.48                                | 6.27                            | 7.00                         | 1.5                                  | 0.932                      |
| 2017              | 6.79  | 6.91                              | 6.59                                | 6.38                            | 7.11                         | 1.5                                  | 0.932                      |
| 2018              | 6.91  | 7.02                              | 6.70                                | 6.49                            | 7.21                         | 1.5                                  | 0.932                      |
| 2019              | 7.02  | 7.14                              | 6.82                                | 6.61                            | 7.32                         | 1.5                                  | 0.932                      |
| 2020              | 7.14  | 7.26                              | 6.94                                | 6.73                            | 7.43                         | 1.5                                  | 0.932                      |
| Thereafter        | Escalation rate of 1.5% thereafter                  |                                   |                                     |                                 |                              |                                      |                            |

Celtic's weighted average realized sales prices for the year ended December 31, 2010 were \$67.38/Bbl for oil and NGLs and \$4.21/Mcf for natural gas, before financial derivative contracts.

**RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE**

**Reserves Reconciliation**

The following table sets forth a reconciliation of Celtic's total gross (before royalty) proved, probable and proved plus probable reserves as at December 31, 2010 against such reserves as at December 31, 2009 based on forecast price and cost assumptions.

| FACTORS             | LIGHT AND MEDIUM OIL |                        |                                    | HEAVY OIL            |                        |                                    | NATURAL GAS LIQUIDS  |                        |                                    |
|---------------------|----------------------|------------------------|------------------------------------|----------------------|------------------------|------------------------------------|----------------------|------------------------|------------------------------------|
|                     | Gross Proved (Mbbbl) | Gross Probable (Mbbbl) | Gross Proved Plus Probable (Mbbbl) | Gross Proved (Mbbbl) | Gross Probable (Mbbbl) | Gross Proved Plus Probable (Mbbbl) | Gross Proved (Mbbbl) | Gross Probable (Mbbbl) | Gross Proved Plus Probable (Mbbbl) |
| December 31, 2009   | 2,554                | 1,896                  | 4,450                              | 396                  | 116                    | 512                                | 5,907                | 4,174                  | 10,081                             |
| Extensions          | 201                  | 230                    | 431                                | -                    | -                      | -                                  | 987                  | 1,942                  | 2,930                              |
| Improved Recovery   | -                    | -                      | -                                  | -                    | -                      | -                                  | -                    | -                      | -                                  |
| Infill Drilling     | 30                   | 10                     | 40                                 | -                    | -                      | -                                  | 505                  | 567                    | 1,072                              |
| Technical Revisions | 351                  | (254)                  | 97                                 | 21                   | (12)                   | 9                                  | 615                  | (865)                  | (250)                              |
| Discoveries         | 88                   | 40                     | 128                                | -                    | -                      | -                                  | 285                  | 135                    | 420                                |
| Acquisitions        | 14                   | 9                      | 23                                 | -                    | -                      | -                                  | 325                  | 238                    | 564                                |
| Dispositions        | (1,182)              | (755)                  | (1,937)                            | -                    | -                      | -                                  | (68)                 | (67)                   | (135)                              |
| Economic Factors    | (15)                 | (12)                   | (27)                               | (1)                  | -                      | -                                  | (78)                 | (36)                   | (114)                              |
| Production          | (299)                | -                      | (299)                              | (45)                 | -                      | (45)                               | (1,142)              | -                      | (1,142)                            |
| December 31, 2010   | 1,742                | 1,165                  | 2,907                              | 371                  | 104                    | 475                                | 7,336                | 6,088                  | 13,425                             |

| FACTORS             | ASSOCIATED AND NON-ASSOCIATED GAS <sup>1</sup> |                       |                                   | COALBED METHANE     |                       |                                   | SHALE GAS           |                       |                                   | COMBINED            |                       |                                   |
|---------------------|--|-----------------------|-----------------------------------|---------------------|-----------------------|-----------------------------------|---------------------|-----------------------|-----------------------------------|---------------------|-----------------------|-----------------------------------|
|                     | Gross Proved (MMcf)                            | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (MBOE) | Gross Probable (MBOE) | Gross Proved Plus Probable (MBOE) |
| December 31, 2009   | 154,708  | 109,824               | 264,532                           | 3,144               | 1,702                 | 4,846                             | -                   | -                     | -                                 | 35,165              | 24,773                | 59,938                            |
| Extensions          | 20,341   | 33,785                | 54,126                            | -                   | -                     | -                                 | 531                 | 1,239                 | 1,770                             | 4,667               | 8,010                 | 12,677                            |
| Improved Recovery   | -  | -                     | -                                 | -                   | -                     | -                                 | -                   | -                     | -                                 | -                   | -                     | -                                 |
| Infill Drilling     | 13,141   | 10,885                | 24,026                            | -                   | -                     | -                                 | -                   | -                     | -                                 | 2,726               | 2,391                 | 5,117                             |
| Technical Revisions | 3,918  | (34,061)              | (30,143)                          | (51)                | 11                    | (40)                              | -                   | -                     | -                                 | 1,631               | (6,806)               | (5,175)                           |
| Discoveries         | 5,942  | 2,597                 | 8,539                             | -                   | -                     | -                                 | 329                 | 166                   | 495                               | 1,418               | 636                   | 2,054                             |
| Acquisitions        | 2,910  | 2,105                 | 5,015                             | -                   | -                     | -                                 | -                   | -                     | -                                 | 824                 | 599                   | 1,423                             |
| Dispositions        | (749)  | (647)                 | (1,396)                           | -                   | -                     | -                                 | -                   | -                     | -                                 | (1,375)             | (930)                 | (2,305)                           |
| Economic Factors    | (1,693)  | (817)                 | (2,510)                           | (436)               | 407                   | (29)                              | -                   | -                     | -                                 | (448)               | (116)                 | (564)                             |
| Production          | (28,659)                                       | -                     | (28,659)                          | (85)                | -                     | (85)                              | -                   | -                     | -                                 | (6,277)             | -                     | (6,277)                           |
| December 31, 2010   | 169,859  | 123,671               | 293,530                           | 2,572               | 2,120                 | 4,692                             | 860                 | 1,405                 | 2,265                             | 38,332              | 28,556                | 66,888                            |

**Note:**

(1) Natural gas volumes include solution gas, associated and non-associated gas.

**ADDITIONAL INFORMATION RELATING TO RESERVES DATA**

**Undeveloped Reserves - Proved Undeveloped Reserves**

The following table sets forth the volumes of gross proved undeveloped reserves that were first attributed in each of Celtic's three most recent financial years and, before that, in the aggregate:

| Year                    | LIGHT AND MEDIUM OIL     |   | NATURAL GAS <sup>(2)</sup> |  | COALBED METHANE         |  | SHALE GAS               |  | NATURAL GAS LIQUIDS      |   |
|-------------------------|--------------------------|---|----------------------------|--|-------------------------|--|-------------------------|--|--------------------------|---|
|                         | First Attributed (Mbbbl) | Cumulative at Year End <sup>(1)</sup> (Mbbbl) | First Attributed (MMcf)    | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (MMcf) | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (MMcf) | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (Mbbbl) | Cumulative at Year End <sup>(1)</sup> (Mbbbl) |
| Aggregate prior to 2008 | -                        | 7   | 8,461                      | 15,224                                       | -                       | 571  | -                       | -  | 257                      | 455   |
| 2008                    | 150                      | 150   | 34,392                     | 41,108                                       | 605                     | 1,332  | -                       | -  | 1,137                    | 1,336   |
| 2009                    | -                        | 150   | 13,397                     | 46,045                                       | 1,197                   | 2,563  | -                       | -  | 705                      | 1,770   |
| 2010                    | 181                      | 181   | 19,513                     | 52,058                                       | -                       | 1,496  | 531                     | 531  | 872                      | 2,200   |

**Notes:**

- (1) Cumulative at year end is cumulative of previous year plus first attributed, less developed during the year.
- (2) Natural gas volumes include solution gas, associated and non-associated gas.

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Celtic gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

**Undeveloped Reserves - Probable Undeveloped Reserves**

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of Celtic's three most recent financial years and, before that, in the aggregate:

| Year                    | LIGHT AND MEDIUM OIL     |   | NATURAL GAS <sup>(2)</sup> |  | COALBED METHANE         |  | SHALE GAS               |  | NATURAL GAS LIQUIDS      |   |
|-------------------------|--------------------------|---|----------------------------|--|-------------------------|--|-------------------------|--|--------------------------|---|
|                         | First Attributed (Mbbbl) | Cumulative at Year End <sup>(1)</sup> (Mbbbl) | First Attributed (MMcf)    | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (MMcf) | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (MMcf) | Cumulative at Year End <sup>(1)</sup> (MMcf) | First Attributed (Mbbbl) | Cumulative at Year End <sup>(1)</sup> (Mbbbl) |
| Aggregate prior to 2008 | 151                      | 645   | 13,776                     | 21,100                                       | -                       | 425  | -                       | -  | 665                      | 801   |
| 2008                    | 75                       | 375   | 60,580                     | 73,757                                       | 348                     | 647  | -                       | -  | 1,875                    | 2,438   |
| 2009                    | -                        | 384   | 33,240                     | 55,337                                       | 820                     | 1,496  | -                       | -  | 1,407                    | 2,029   |
| 2010                    | 209                      | 509   | 37,938                     | 65,275                                       | -                       | 1,782  | 1,239                   | 1,239  | 2,211                    | 3,464   |

**Notes:**

- (1) Cumulative at year end is cumulative of previous year plus first attributed, less developed during the year.
- (2) Natural gas volumes include solution gas, associated and non-associated gas.

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

**Significant Factors or Uncertainties Affecting Reserves Data**

The process of estimating reserves is complex. It required significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Celtic's reserves are evaluated by Sproule, an independent engineering firm.

Estimates made are reviewed and revised, either upward to downward, as warranted by new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Celtic's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

## Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves, in each instance using forecast prices and costs.

| Year                      | Undiscounted Forecast Prices and Costs |                                     |
|---------------------------|--|-------------------------------------|
|                           | Proved Reserves (M\$)                  | Proved Plus Probable Reserves (M\$) |
| 2011                      | 104,970                                | 148,884                             |
| 2012                      | 17,690                                 | 50,327                              |
| 2013                      | 11,829                                 | 14,219                              |
| 2014                      | -                                      | -                                   |
| 2015                      | 11                                     | 11                                  |
| Remaining Years           | 931                                    | 953                                 |
| <b>Total Undiscounted</b> | <b>135,431</b>                         | <b>214,394</b>                      |

The Corporation has established a \$180.0 million capital program to fund its exploration and development activities for 2011. The Corporation's capital program does not include any new acquisition opportunities, which would likely be financed through debt or equity financings.

Celtic estimates that its internally generated cash flow, drilling royalty credits, proceeds from asset dispositions and unused bank credit facilities will be sufficient to fund the future development costs disclosed above. Celtic typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operating activities, debt financing when appropriate and new equity issues, if available on favourable terms.

## OTHER OIL AND GAS INFORMATION

### Oil and Gas Properties and Wells

Celtic has one core area; West Central Alberta; and four minor areas; Northeastern B.C.; Northern Alberta, East Central Alberta and Southern Alberta, all of which are the subject of the Sproule Report. The term "net", when used to describe the Corporation's share of production, means the total of the Corporation's working interest share before deducting royalties owned by others.

#### Northern Alberta

Utikuma Lake: The Corporation has interests in 6,560 gross (2,744 net) acres in this area which is located 110 kilometres south east of Peace River, Alberta.

#### West Central Alberta

Greater Kaybob: The Corporation has interests in 170,746 gross (130,418 net) acres in this area which is located 15 to 45 kilometres south of Fox Creek, Alberta.

Greater Resthaven: The Corporation has interests in 417,192 gross (400,738 net) acres in this area which is centred 70 kilometres south east of Grant Prairie, Alberta.

#### East Central Alberta

Ashmont/Figure Lake/Edwand: The Corporation holds interests in 59,520 gross (55,122 net) acres in this area which is located 45 kilometres north west of St. Paul, Alberta.

#### Southern Alberta

Bantry/Princess: The Corporation has interests in 7,637 gross (4,916 net) acres in this area which is located 50 kilometres north west of Medicine Hat, Alberta.

Drumheller and Michichi: The Corporation has interests in 22,433 gross (7,825 net) acres in this area which is located 100 kilometres north east of Calgary, Alberta.

### Northeastern B.C.

Inga: The Corporation has interests in 10,508 gross (4,203 net) acres in this area which is located 50 kilometres north west of Ft. St. John, British Columbia.

### Wells

As at December 31, 2010, the Corporation had an interest in 441 gross (275.0 net) producing and 290 gross (167.2 net) non-producing oil and natural gas wells and 18 gross (14.0 net) service wells as follows.

| Location         | PRODUCING            |                    |             |              | NON-PRODUCING |             |             |              | SERVICE WELLS |             |
|------------------|----------------------|--------------------|-------------|--------------|---------------|-------------|-------------|--------------|---------------|-------------|
|                  | Oil                  |                    | Natural Gas |              | Oil           |             | Natural Gas |              | Gross         | Net         |
|                  | Gross <sup>(1)</sup> | Net <sup>(2)</sup> | Gross       | Net          | Gross         | Net         | Gross       | Net          |               |             |
| Alberta          | 92                   | 64.9               | 344         | 208.5        | 79            | 56.4        | 204         | 109.2        | 18            | 14.0        |
| British Columbia | -                    | -                  | 5           | 1.6          | -             | -           | 2           | 0.8          | -             | -           |
| Saskatchewan     | -                    | -                  | -           | -            | 3             | 0.6         | 2           | 0.2          | -             | -           |
| <b>TOTAL</b>     | <b>92</b>            | <b>64.9</b>        | <b>349</b>  | <b>210.1</b> | <b>82</b>     | <b>57.0</b> | <b>208</b>  | <b>110.2</b> | <b>18</b>     | <b>14.0</b> |

#### Notes:

- (1) "Gross" wells means the number of wells in which Celtic has a working interest or a royalty interest that may be convertible to a working interest.
- (2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Celtic's percentage working interest therein.
- (3) In addition, Celtic has an interest in 48 gross (1.6 net) producing oil and natural gas wells and 101 gross (3.5 net) non-producing wells and 5 gross (0.2 net) service wells, none of which are operated by Celtic and all of which are unitized, in the Leduc Woodbend D-2 and D-3 Units, all of which are located in Alberta.

### Properties With No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year.

| UNPROVED PROPERTIES - UNDEVELOPED LAND<br>(acres) |                      |                    |                            |
|---|----------------------|--------------------|----------------------------|
| LOCATION  | Gross <sup>(1)</sup> | Net <sup>(2)</sup> | Net Area to Expire in 2011 |
| Alberta   | 676,036              | 616,116            | 49,920                     |
| British Columbia                                  | 9,957                | 5,083              | -                          |
| <b>TOTAL</b>                                      | <b>685,993</b>       | <b>621,199</b>     | <b>49,920</b>              |

#### Notes:

- (1) "Gross Acres" are the total acres in which Celtic has or had an interest.
- (2) "Net Acres" is the aggregate of the total acres in which Celtic has or had an interest multiplied by Celtic's working interest percentage held therein.

There are no costs or work commitments associated with Celtic's non-producing properties except for annual lease rental payments.

### Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves.

Significant economic factors and uncertainties affect the anticipated development or production activities on certain of the Corporation's properties with no attributed reserves. Celtic is currently in the process of installing a 12 inch pipeline, which will run through the centre of the Resthaven property, acting as a main gathering line for all wells. There are several gas plants in the area which Celtic can process in its gas through as it continues to de-risk and develop the play.

## Forward Contracts

Celtic may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. (See "General Development of the Business - Future Commitments").

## Additional Information Concerning Abandonment and Reclamation Costs

Celtic estimates the costs associated with well abandonment and reclamation based on its previous experience, current regulations, costs, technology and industry standards area by area. Celtic expects to incur abandonment and reclamation costs on 749 gross wells (456.3 net wells), together with 5.2 net unitized wells comprising currently producing, non-producing and service wells. Celtic's share of the expected total abandonment and reclamation costs for wells with assigned reserves, non-producing and service wells and facilities, net of salvage value are summarized, without discount and using a discount rate of 10%, in the following table:

| Category  | Forecast Pricing (M\$) |                |                          |                           |
|---|------------------------|----------------|--------------------------|---------------------------|
|   | Proved NPV 0%          | Proved NPV 10% | Proved + Probable NPV 0% | Proved + Probable NPV 10% |
| Wells with reserves assigned <sup>(1)</sup>                   | 11,163                 | 2,853          | 14,354                   | 2,233                     |
| Wells with reserves assigned <sup>(2)</sup>                   | 8,435                  | 2,156          | 10,846                   | 1,687                     |
| Wells with no reserves assigned and facilities <sup>(3)</sup> | 19,392                 | 4,956          | 23,696                   | 3,686                     |
| Total abandonment and reclamation cost provision              | 38,990                 | 9,965          | 48,896                   | 7,606                     |
| Portion forecast to be paid during the next three years:      |                        |                |                          |                           |
| Included in Sproule Report <sup>(1)</sup>                     | 238                    | 197            | 139                      | 117                       |
| Not included in Sproule Report <sup>(2) (3)</sup>             | 180                    | 149            | 105                      | 88                        |
| Total over the next three years                               | 418                    | 346            | 244                      | 205                       |

### Notes:

- (1) Abandonment and disconnect costs were estimated by Sproule and are included in the Sproule Report for all wells assigned reserves and for all un-drilled locations assigned reserves.
- (2) Reclamation costs, for wells assigned reserves and for all un-drilled locations assigned reserves, are not included in the Sproule Report but were estimated by Celtic.
- (3) Celtic has estimated the timing and costs associated with the abandonment and reclamation for wells with no reserves assigned and for facilities. These costs were not included in the Sproule Report.

## Tax Horizon

At the end of 2010, Celtic had estimated income tax deductions of approximately \$455 million available to reduce future taxable income. As a result of available deductions and Celtic's planned capital expenditures for 2011, the Corporation does not expect to incur current income taxes in 2011. The Corporation could, if sufficient income tax deductions are not generated by future business operations, incur income taxes in 2012.

## Costs Incurred

The following table summarizes Celtic's property acquisition costs, exploration costs and development costs (before property dispositions, and drilling royalty credits) incurred during the financial year ended December 31, 2010.

| Property Acquisitions and Capital Expenditures |                |
|--|----------------|
| Nature of cost                                 | Amount (M\$)   |
| Property Acquisition Costs                     |                |
| Proved   | 7,703          |
| Unproved                                       | -              |
| Exploration Costs                              | 61,722         |
| Development Costs                              | 169,268        |
| <b>Total</b>                                   | <b>238,693</b> |

### Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2010.

| Wells              | Gross     | Net         |
|--------------------|-----------|-------------|
| <b>Development</b> |           |             |
| Gas                | 48        | 29.5        |
| Oil                | 2         | 2.0         |
| Coalbed Methane    | 2         | 1.6         |
| Shale Gas          | -         | -           |
| Stratigraphic Test | -         | -           |
| Unsuccessful       | 3         | 3.0         |
| <b>Exploratory</b> |           |             |
| Gas                | 4         | 3.5         |
| Oil                | -         | -           |
| Coalbed Methane    | -         | -           |
| Shale Gas          | 2         | 1.3         |
| Stratigraphic Test | -         | -           |
| Unsuccessful       | 1         | 1.0         |
| <b>Total</b>       | <b>62</b> | <b>41.9</b> |

Celtic's initial plans for 2011 include a \$180.0 million capital expenditure program, funded from cash flow from operating activities, bank debt and non-core property dispositions.

### Production Estimates

The following table discloses by product type the volume of Celtic's working interest share of production estimated before the deduction of royalties plus Celtic's royalty interest share of production for the first year for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2010, based on forecast prices and costs.

| Corporation                       | Light and Medium Oil (Bbl/d) | Heavy Oil (Bbl/d) | Natural Gas (Mcf/d) | Natural Gas Liquids (Bbl/d) | Coalbed Methane (Mcf/d) | Shale Gas (Mcf/d) | COMBINED (BOE/d) |
|-----------------------------------|------------------------------|-------------------|---------------------|-----------------------------|-------------------------|-------------------|------------------|
| <b>Proved</b>                     |                              |                   |                     |                             |                         |                   |                  |
| Developed producing               | 579                          | 101               | 65,437              | 2,806                       | 235                     | -                 | 14,430           |
| Developed non-producing           | 132                          | 2                 | 5,972               | 272                         | 325                     | 141               | 1,479            |
| Undeveloped                       | 45                           | -                 | 12,412              | 522                         | 255                     | -                 | 2,678            |
| <b>Total Proved</b>               | <b>756</b>                   | <b>103</b>        | <b>83,821</b>       | <b>3,600</b>                | <b>815</b>              | <b>141</b>        | <b>18,587</b>    |
| Probable                          | 55                           | 3                 | 15,972              | 696                         | 228                     | 22                | 3,459            |
| <b>Total Proved Plus Probable</b> | <b>811</b>                   | <b>106</b>        | <b>99,793</b>       | <b>4,296</b>                | <b>1,043</b>            | <b>163</b>        | <b>22,046</b>    |

One property, namely, the Greater Kaybob property, has production in excess of 20% of the estimated combined production set forth in the immediately preceding table. The estimated average daily volume of production for the first year for the Greater Kaybob property as reported in the Sproule Report is as follows:

| <b>Greater Kaybob</b>             | <b>Light and Medium Oil (Bbl/d)</b> | <b>Natural Gas (Mcf/d)</b> | <b>Shale Gas (Mcf/d)</b> | <b>Natural Gas Liquids (Bbl/d)</b> | <b>Combined (BOE/d)</b> |
|-----------------------------------|-------------------------------------|----------------------------|--------------------------|------------------------------------|-------------------------|
| <b>Proved</b>                     |                                     |                            |                          |                                    |                         |
| Developed producing               | 75                                  | 58,455                     | -                        | 2,614                              | 12,432                  |
| Developed non-producing           | 105                                 | 3,358                      | 141                      | 218                                | 907                     |
| Undeveloped                       | -                                   | 10,856                     | -                        | 456                                | 2,265                   |
| <b>Total Proved</b>               | <b>180</b>                          | <b>72,668</b>              | <b>141</b>               | <b>3,288</b>                       | <b>15,603</b>           |
| Probable                          | 29                                  | 12,030                     | 22                       | 545                                | 2,583                   |
| <b>Total Proved Plus Probable</b> | <b>209</b>                          | <b>84,698</b>              | <b>163</b>               | <b>3,833</b>                       | <b>18,186</b>           |

### Production History

The following table summarizes Celtic's average daily production before deduction of royalties, for the periods indicated.

| <b>Product</b>              | <b>2010</b>   |               |               |               |               |
|-----------------------------|---------------|---------------|---------------|---------------|---------------|
|                             | <b>Year</b>   | <b>Q4</b>     | <b>Q3</b>     | <b>Q2</b>     | <b>Q1</b>     |
| Light & Medium Oil (Bbls/d) | 819           | 664           | 615           | 850           | 1,153         |
| Heavy Oil (Bbls/d)          | 123           | 123           | 114           | 118           | 137           |
| NGLs (Bbls/d)               | 3,128         | 3,309         | 3,018         | 3,176         | 3,007         |
| Natural Gas (Mcf/d)         | 78,521        | 78,824        | 75,742        | 82,389        | 77,141        |
| Coalbed Methane (Mcf/d)     | 233           | 217           | 233           | 232           | 250           |
| Shale Gas (Mcf/d)           | -             | -             | -             | -             | -             |
| Sulphur (Lt/d)              | 65            | 69            | 58            | 69            | 64            |
| <b>Total (BOE/d)</b>        | <b>17,304</b> | <b>17,385</b> | <b>16,506</b> | <b>18,029</b> | <b>17,302</b> |

### Netback History

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

| Category                            | 2010  |       |       |       |       |
|-------------------------------------|-------|-------|-------|-------|-------|
|                                     | Year  | Q4    | Q3    | Q2    | Q1    |
| Selling prices <sup>(1)</sup>       |       |       |       |       |       |
| Oil & NGLs (\$/Bbl)                 | 67.80 | 68.56 | 62.29 | 69.12 | 70.65 |
| Natural gas (\$/Mcf)                | 4.37  | 3.93  | 4.22  | 4.18  | 5.18  |
| Royalties                           |       |       |       |       |       |
| Oil & NGLs (\$/Bbl)                 | 12.18 | 13.07 | 9.96  | 10.67 | 14.76 |
| Natural gas (\$/Mcf)                | 0.26  | 0.07  | 0.19  | 0.20  | 0.59  |
| Transportation and selling expenses |       |       |       |       |       |
| Oil & NGLs (\$/Bbl)                 | 0.18  | 0.09  | 0.11  | 0.21  | 0.30  |
| Natural gas (\$/Mcf)                | 0.09  | 0.07  | 0.08  | 0.07  | 0.13  |
| Production expenses <sup>(2)</sup>  |       |       |       |       |       |
| Oil & NGLs (\$/Bbl)                 | 9.94  | 7.61  | 9.46  | 10.02 | 12.56 |
| Natural gas (\$/Mcf)                | 1.26  | 1.02  | 1.29  | 1.39  | 1.36  |
| Operating netbacks                  |       |       |       |       |       |
| Oil & NGLs (\$/Bbl)                 | 45.50 | 47.79 | 42.76 | 48.22 | 43.03 |
| Natural gas (\$/Mcf)                | 2.76  | 2.77  | 2.66  | 2.52  | 3.10  |

**Notes:**

- (1) Selling prices includes realized gains and losses from financial derivative instruments.  
(2) Production expenses include mineral lease and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

**Production Volume by Field**

The following table discloses for each important field, and in total, Celtic's production volumes for the financial year ended December 31, 2010 for each product type.

| Field                      | Light and Medium Oil (Bbls/d) | Heavy Oil (Bbls/d) | Natural Gas Liquids (Bbls/d) | Natural Gas (Mcf/d) | Coalbed Methane (Mcf/d) | Shale Gas (Mcf/d) | Sulphur (Lt/d) | Combined (BOE/d) | %          |
|----------------------------|-------------------------------|--------------------|------------------------------|---------------------|-------------------------|-------------------|----------------|------------------|------------|
| Greater Kaybob             | 122                           | -                  | 2,910                        | 71,839              | -                       | -                 | 65             | 15,113           | 87.3       |
| Greater Resthaven          | 21                            | -                  | 27                           | 1,580               | -                       | -                 | -              | 311              | 1.8        |
| Michichi/Drumheller        | 25                            | -                  | 22                           | 1,947               | 233                     | -                 | -              | 411              | 2.4        |
| Princess/Bantry            | 275                           | -                  | 5                            | 299                 | -                       | -                 | -              | 330              | 1.9        |
| Ashmont/Edward/Figure Lake | -                             | 12                 | -                            | 1,138               | -                       | -                 | -              | 201              | 1.2        |
| Utikuma                    | 139                           | -                  | 8                            | 14                  | -                       | -                 | -              | 150              | 0.9        |
| Inga                       | -                             | -                  | 1                            | 9                   | -                       | -                 | -              | 3                | -          |
| Other                      | 236                           | 111                | 156                          | 1,695               | -                       | -                 | -              | 785              | 4.5        |
| <b>TOTAL</b>               | <b>819</b>                    | <b>123</b>         | <b>3,128</b>                 | <b>78,521</b>       | <b>233</b>              | <b>-</b>          | <b>65</b>      | <b>17,304</b>    | <b>100</b> |

**RISK FACTORS**

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Celtic.

## **Exploration, Development and Production Risks**

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by Celtic will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

## **Prices, Markets and Marketing of Crude Oil and Natural Gas**

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Celtic. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Celtic's oil and gas production. Celtic might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Celtic's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Celtic will be in part determined by the borrowing base of Celtic. A sustained material decline in prices from historical average prices could reduce Celtic's future borrowing base, therefore reducing the bank credit available to Celtic, and could require that a portion of any existing bank debt of Celtic be repaid.

In addition to establishing markets for its oil and natural gas, Celtic must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Celtic will be affected by numerous factors beyond its control. Celtic will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Celtic. The ability of Celtic to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Celtic will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Celtic has limited direct experience in the marketing of oil and natural gas.

## **Capital Markets**

Notwithstanding the on-going recovery in the global economic situation, Celtic, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity. Although Celtic's business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, non-core property dispositions, borrowings and possible future equity sales, Celtic's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Celtic's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, Celtic's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on current funds available and expected funds generated from operations, Celtic believes it has sufficient funds available to fund its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if Celtic incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for Celtic's capital expenditure plans may result in a delay in development or production on Celtic's properties.

## **Regulatory**

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Celtic's operations may require licences from various governmental authorities. There can be no assurance that Celtic will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects. It is not expected that any of these controls or regulations will affect the operations of Celtic in a manner materially different from how they would affect other oil and natural gas companies of similar size.

## **Insurance**

Celtic's involvement in the exploration for and development of oil and gas properties may result in Celtic becoming subject to liability for pollution, blow-outs, property damage, personal injury and other hazards. Although Celtic will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Celtic may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Celtic. The occurrence of a significant event that Celtic is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Celtic's financial position, results of operations or prospects.

## **Operational Dependence**

Other companies operate some of the assets in which Celtic has an interest. As a result, Celtic will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Celtic's financial performance. Celtic's return on assets operated by others will therefore depend upon a number of factors that may be outside of Celtic's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

## **Project Risks**

Celtic will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Celtic's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Celtic's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;

- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Celtic could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

### **Variations in Foreign Exchange Rates and Insurance Rates**

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted Celtic's operating entities production revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of Celtic's reserves as determined by independent evaluators.

To the extent that Celtic engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Celtic may contract.

An increase in interest rates could result in a significant increase in the amount Celtic pays to service debt, which could negatively impact the market price of Celtic's Common Shares.

### **Substantial Capital Requirements; Liquidity**

Celtic anticipates that it will make substantial capital expenditures for the acquisition, exploration development and production of oil and natural gas reserves in the future. If Celtic's future revenues or reserves decline, Celtic may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Celtic. Moreover, future activities may require Celtic to alter its capitalization significantly. The inability of Celtic to access sufficient capital for its operations could have a material adverse effect on Celtic's financial condition, results of operations or prospects.

### **Competition**

Celtic will actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Celtic. Celtic's competitors will include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Celtic's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personal resources available to them than Celtic.

Certain of Celtic's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Celtic's ability to sell or supply oil or gas to these

customers in the future. Celtic's ability to successfully bid on and acquire additional property rights, to discover reserves to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

## **Title**

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Celtic will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Celtic may lose all or a portion of its right title and interest in and to the properties to which the title defects relate.

## **Environmental Risks**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require Celtic to incur costs to remedy such discharge. Implementation of strategies with respect to climate change and reducing greenhouse gases whether to meeting the limits required by the Kyoto Protocol or a otherwise determined by the federal or provincial governments could have material impact on the nature of oil and natural gas operations, including those of Celtic. See "*Industry Conditions – Environmental Regulation*". No assurance can be given that the application of environmental laws to the business and operations of Celtic will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Celtic's financial condition, results of operations or prospects.

## **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Celtic's control. The information concerning reserves and associated cash flow set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Celtic's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the Sproule Report, and such variations could be material. The Sproule Report is based in part on the assumed success of activities Celtic intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Sproule Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Sproule Report.

The Sproule Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in Celtic's reserves since that date.

### **Reserve Replacement**

Celtic's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Celtic successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Celtic may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Celtic's reserves will depend not only on Celtic's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Celtic's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

### **Reliance on Operators and Key Employees**

To the extent Celtic is not the operator of its oil and gas properties, Celtic will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of Celtic will be largely dependent upon the performance of its management and key employees. Celtic does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Celtic.

### **Geo-Political Risks**

The marketability and price of oil and natural gas that may be acquired or discovered by Celtic is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Celtic's net production revenue.

In addition, Celtic's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Celtic's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Celtic. Celtic will not have insurance to protect against the risk from terrorism.

### **Dividends**

To date, Celtic has not paid any dividends on its Common Shares and does not anticipate the payment of any dividends on its Common Shares for the foreseeable future.

### **Conflicts of Interest**

Certain of the directors and officers of Celtic are also directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Celtic and as officers and directors of such other companies. Such

conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

### **Dilution**

Celtic may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Celtic which may be dilutive.

### **Management of Growth**

Celtic may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Celtic to manage growth effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The inability of Celtic to deal with this growth could have a material adverse impact on its business, operations and prospects.

### **Expiration of Licences and Leases**

Celtic's properties are held in the form of licences and leases and working interests in licences and leases. If Celtic or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of Celtic's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on results of operations and business.

### **Permits and Licenses**

The operations of Celtic may require licenses and permits from various governmental authorities. There can be no assurance that Celtic will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its properties.

### **Additional Funding Requirements**

Celtic's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Celtic may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Celtic to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Celtic's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Celtic's ability to expend the necessary capital to replace its reserves or to maintain its production. If Celtic's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or be available on favourable terms. Any equity financing may result in a change of control of Celtic or holders of Common Shares suffering further dilution.

### **Issuance of Debt**

From time to time Celtic may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Celtic's debt levels above industry standards. Neither Celtic's articles nor its bylaws limit the amount of indebtedness that Celtic may incur. The level of Celtic's indebtedness from time to time could impair Celtic's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Celtic's ability to meet its debt service obligations will depend on Celtic's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Celtic. As certain of the indebtedness of Celtic bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Celtic's interest payment obligations and could have a material adverse effect on Celtic's financial condition and results of operations. Further, Celtic's indebtedness is secured by substantially all of Celtic's assets. In the event of a violation by Celtic of any of its loan covenants or any other default by Celtic on its obligations relating to its indebtedness, the

lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Celtic's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

### **Hedging**

From time to time Celtic may enter into agreements to receive fixed prices on its oil and natural gas production to offset risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Celtic will not benefit from such increases. Similarly, from time to time Celtic may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar, however, if the Canadian dollar declines in value compared to the United States dollar, Celtic will not benefit from its fluctuating exchange rate.

### **Availability of Drilling Equipment and Access Restrictions**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Celtic and may delay exploration and development activities.

### **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. Celtic is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on Celtic and its operations.

### **Seasonality**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of Celtic's exploration and development activities, which could in turn have a material adverse impact on Celtic's business, operations and prospects.

### **Third Party Credit Risk**

Celtic is, or may be exposed to, third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Celtic, such failures could have a material adverse effect on Celtic and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Celtic's ongoing capital program, potentially delaying the program and the results of such program until Celtic finds a suitable alternative partner.

### **Kyoto Protocol**

Canada is a signatory to the United Nations Framework Convention on Climate Change. Canada has ratified the Kyoto Protocol established thereunder and is thereby required to establish legally binding targets to reduce nation wide emissions of carbon dioxide, methane, nitrous oxide and other "greenhouse gases". Celtic's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject Celtic to legislation in Canada regulating emissions of

greenhouse gases. The Government of Canada put forward in April 2007, and March 2008, its "Turning the Corner" climate change plan that proposes regulations to set greenhouse gas "emissions intensity" reduction requirements for certain industrial sectors by 18% from 2006 levels, commencing in 2010, and including oil and gas exploration and production. This may require the reduction of emissions or emissions intensity from Celtic's operations and facilities. The Province of Alberta implemented the Specified Gas Emitters Regulation under its Climate Change Emissions Management Act on July 1, 2007. This regulation requires facilities which emit in excess of 100,000 tonnes of greenhouse gases per year to reduce their emissions intensity by 12% from a baseline derived from the average of 2003 2005 emissions. The direct and indirect costs of complying with these emissions regulations may adversely affect the business of Celtic. See "*Industry Conditions – Environmental Regulation*".

### **Alternatives to and Changing Demand for Petroleum Products**

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Celtic cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Celtic's business, financial condition, results of operations and cash flows.

### **International Financial Reporting Standards**

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, effective January 1, 2011. IFRS will require increased financial statement disclosure as compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Celtic. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Corporation's reported financial position and results of operations. Celtic is finalizing completion of the conversion to IFRS and has adopted IFRS effective January 1, 2011.

## **INDUSTRY CONDITIONS**

### **Canadian Government Regulation**

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Celtic in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and Celtic is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

### **Pricing and Marketing – Oil**

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such licence requires the approval of the Governor in Council.

## **Pricing and Marketing – Natural Gas**

The price of natural gas is determined by negotiation between buyers and seller. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such licence requires the approval of the Governor in Council.

The governments of British Columbia, Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve ability, transportation arrangements and market considerations.

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the prorating of capacity on the interprovincial pipeline systems continues to limit oil exports.

### **Pipeline Capacity**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. The pro rating of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

### **The North American Free Trade Agreement**

The North American Free Trade Agreement (“**NAFTA**”) among the governments of Canada, the United States and Mexico become effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - U.S. Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

### **Provincial Royalties and Incentives**

#### Provincial Royalties and Incentives

##### (a) General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, NGL, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from

time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers.

With the elimination of the corporate surtax effective January 1, 2008 and other recently enacted rate reductions initially introduced in the October 2007 Economic Statement, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

(b) Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008. The NRF took effect on January 1, 2009.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool.

The new royalty formula for conventional oil operates on a sliding rate formula containing separate elements that account for oil price and well production. Royalty rates for conventional oil range up to 50 percent, an increase from the previous maximums of 30 percent to 35 percent depending on the vintage of the oil, with rate caps once the price of conventional oil reaches \$120 per Bbl.

Under the NRF, natural gas royalties are set by a sliding rate formula sensitive to price, production volume and measured well depth. New natural gas royalty rates range from 5 percent to 50 percent, an increase from the previous maximums of 5 percent to 35 percent, with rate caps once the price of natural gas reaches \$17.50/MMbtu. Royalties for natural gas liquids are set at 40 percent for pentanes and 30 percent for butanes and propane.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta announced its plan to implement two new deep resource royalty programs to address some of the unintended consequences of the NRF. These two, five-year royalty programs, which were implemented with the NRF on January 1, 2009, were designed to encourage the continued development of deep, high-cost oil and gas reserves.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program

wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty will revert to royalty rates determined by the NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a \$200 per meter royalty credit is available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available are determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Celtic's 2008 production it is entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program applies to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 Bbls of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentives for one year to March 31, 2011. The three-point incentive program also includes an investment of \$30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

On March 11, 2010, the Government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

- Permanent 5% front-end royalty
  - The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits.
- Lower Maximum Rates
  - The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.
  - Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.
- Implementation/Transition
  - All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production after January 1, 2011.
  - The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
  - The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

On May 27, 2010, the Government of Alberta announced the royalty curve revisions including initiatives to stimulate new energy investments and new technology. As part of this initiative, a front end royalty of 5% for each of new shale gas, coalbed methane, horizontal gas and horizontal oil well was put in place and is subject to certain time and volume limits for each type of well. The shale gas and coalbed methane royalty rates apply to well events that start producing gas exclusively from shale or coal zones, as applicable, on or after May 2010. The horizontal gas and horizontal oil well royalty rates apply to wells drilled or spud on or after May 2010.

The new well royalty rate (applicable to wells classified as an "oil", "gas", or "crude bitumen" well when it commences or recommences production on or after April 2009) became a permanent feature of the

royalty system effective May 2010. The maximum and minimum royalty rates in Alberta for conventional oil are 40% and 0% respectively. The conventional oil quantity component was kept the same as the existing royalty framework and the price component for natural gas was changed to moderate the increase in the rate at prices higher than \$535/m<sup>3</sup>. The maximum and minimum royalty rates in Alberta for natural gas are 36% and 5% respectively with the royalty rate being the sum of a price component and the quantity component. The natural gas quantity component was kept the same as the existing royalty framework and the component for natural gas was changed to moderate the increase in the rate at prices higher than \$5.25 per GJ.

(c) British Columbia

The general oil and gas royalty structure in British Columbia is based on a sliding scale. As the price the producer receives for the gas goes up, so do the royalties that producer pays to the Province. However, the majority of gas produced in the province is also subject to a hard cap on the percentage of royalties paid. Parts 10 and 11 of the Petroleum and Natural Gas Act (the "**PNG Act**"), contain the primary legislative provisions for royalties and freehold production taxes on oil and gas in British Columbia. The Crown receives a royalty on any oil and gas production from Crown Land "permitted, licensed or leased" under the PNG Act. Authority is given to prescribe by Regulation the royalty rate, who must pay it, when it must be paid, as well as penalties for late or non-payment, and any other related considerations. The calculation of royalties payable for different classes of petroleum and natural gas and most of the practices and procedures to be followed are set out in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Natural gas is divided into ten categories, each with different royalty rates, which vary depending on the type of gas it is, whether it is freehold or Crown reserve and whether it is conservation or non-conservation gas. The results of failing to pay the royalties due can be significant, ranging from the imposition of penalties and interest to the Minister outright cancelling a permit, licence or lease pursuant to Section 135 of the PNG Act. The government has developed a number of royalty credit programs for certain types of drilling and wells. These include the following:

- Summer Royalty Program - provides a lump sum royalty credit of the lesser of \$100,000 or 10% of drilling and completion costs for wells drilled between April 1 to November 30 each year to encourage resource development outside of the traditional drilling season;
- Deep Royalty Credit Program (Deep, Deep Discovery, Deep Re-entry) - royalty credits are assigned based on depth, location and gas quality and is designed to target very expensive and geologically complex deep resources and which program was enhanced in February 2009 and August 2009, including to encourage greater drilling activities and allow horizontal wells starting at 1,900 metres total vertical depth to qualify for such program;
- Marginal Royalty Program - provides a reduced royalty rate based on well productivity for wells with a 12 month average rate of less than 80 Mcf/d/100m and monthly production below 880 Mcf/d;
- Ultra-Marginal Royalty Program - provides a reduced royalty rate based on well productivity for wells with a 12 month average rate of 40 Mcf/d/100m;
- Coalbed Methane Royalty Program - provides a royalty reduction for coalbed gas wells and a royalty credit of \$50,000 for wells drilled on Crown lands and a tax credit of \$30,000 for wells drilled on freehold lands;
- Infrastructure Royalty Program - provides up to 50% of the costs of building high grade oil and gas roads and pipelines in royalty credits in order to promote activity in areas with limited infrastructure (roads/pipelines) on specific construction or drilling projects that must be approved in advance; and
- Net Profit Royalty Program - provides a 3 Tier system with low royalty rates in initial stages in exchange for higher rates in later stages in order to promote the development of remote and expensive-to-extract resources.

Under the British Columbia royalty regime, a temporary 2% gas royalty program was introduced effective September 1, 2009 whereby all natural gas wells with a spud date after August 31, 2009 and before July 1, 2010 are eligible for the 2% gas royalty, for a 12 month period, provided they commence continuous production before December 31, 2010. British Columbia has a maximum natural gas royalty rate of 27% and a maximum conventional oil royalty rate of 18%.

(d) Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are between 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that excess approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.
- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/tax rates and new incentive volumes.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate (“**RTR**”) as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada’s initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan’s RTR will be wound down as a result of the Government of Canada’s plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

## **Land Tenure**

Crude oil and natural gas located in the western provinces is owned predominately by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

## **Environmental Regulation**

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

The Province of Alberta’s environmental legislation is the Environmental Protection and Enhancement Act (Alberta) (the “**EPEA**”), the Oil and Gas Conservation Act (“**OGCA**”) and directives and guidelines issued by both Alberta Environment and the Energy Resources Conservation Board (“**ERCB**”). The EPEA and OGCA impose environmental standards with respect to releases of effluents and emissions, including reporting and monitoring obligations, and impose significant penalties for non compliance. For example, regulations enacted under the EPEA target sulphur oxide and nitrous oxide emissions from oil and gas operations. In addition, the greenhouse gas emissions intensity reduction requirement of the Specified Gas Emitters Regulation implemented under the Climate Change and Emissions Management Act (Alberta) came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%.

On May 11, 2009, the Government of Saskatchewan announced The Management and Reduction of Greenhouse Gases Act (the “**MRGGA**”) to regulate greenhouse gas emissions in the province. Although the MRGGA has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that the MRGGA will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

In December, 2002, the Government of Canada ratified the Kyoto Protocol (“**Protocol**”). Bill C 288, which is intended to ensure that Canada meets its global climate change obligations under the Protocol, was

passed by the House of Commons on February 14, 2007. It is questionable, however, whether the Federal Government will enforce the Protocol's target of 6% below 1990 emission levels.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**"). The Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Federal Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be facility specific for the oil and gas industry. For new facilities (including major expansions constituting more than a 25% increase in a facility's physical capacity) the 2% yearly emissions intensity reduction target will begin to apply on the fourth year of commercial operation, and the baseline will be the third year's emissions intensity.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) for natural gas pipelines, 50,000 tonnes of CO<sub>2</sub> equivalent per year; and (ii) for upstream oil and gas facilities 3,000 tonnes of CO<sub>2</sub> equivalent per year or 10,000 BOE/d/company. These proposed thresholds are significantly more strict than the current Alberta regulatory threshold of 100,000 tonnes of CO<sub>2</sub> equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at \$15 per tonne for the 2010 to 2012 period, rising to \$20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018.

Celtic intends to meet its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA, the OGCA and similar legislation in other jurisdictions in which it operates. Celtic believes that it is in material compliance with applicable environmental laws and regulations. It also believes that it is reasonably likely that the trend towards strict standards in environmental legislation and regulation will continue.

Given the evolving nature of the debate related to climate change, the regulation of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on Celtic and its operations and financial condition at this time.

## **DIVIDENDS OR DISTRIBUTIONS**

Celtic has not declared or paid any dividends or made any distributions since its incorporation and does not foresee the declaration or payment of dividends or distributions in the near future. Any decision to pay dividends or distributions on its shares will be made by the board of directors on the basis of Celtic's earnings, financial requirements and other conditions existing at such future time.

## DESCRIPTION OF SHARE CAPITAL

### General Description of Share Capital

Celtic is authorized to issue an unlimited number of Common Shares without nominal or par value, of which, as at March 4, 2011, 91,448,926 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, 5,975,896 Common Shares are reserved for options to be granted to directors, officers, employees and certain consultants of Celtic. Celtic is also authorized to issue an unlimited number of preferred shares (“**Preferred Shares**”), without nominal or par value. To date, no Preferred Shares have been issued.

### Common Shares

The holders of Celtic’s Common Shares are entitled to dividends as and when declared by the board of directors of Celtic, to one vote per share at meetings of shareholders of Celtic and, upon liquidation, to receive such assets of Celtic as are distributable to the holders of the Common Shares.

### Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the board of directors of Celtic who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. There are no Preferred Shares issued and outstanding as at the date hereof.

The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Celtic, whether voluntary, or any other distribution of the assets of Celtic among its shareholders for the purpose of winding-up its affairs, rank equally with the Preferred Shares of every other series and shall be entitled to preference over the Common Shares, and the shares of any other class ranking junior to the Preferred Shares.

## MARKET FOR SECURITIES

### Price Range and Volume of Trading of Common Shares

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares of Celtic on the Toronto Stock Exchange as reported by sources Celtic believes to be reliable for the periods indicated:

| Date        | Price Range (\$) |       |       | Trading Volume |
|-------------|------------------|-------|-------|----------------|
|             | High             | Low   | Close |                |
| <b>2010</b> |                  |       |       |                |
| January     | 22.10            | 19.80 | 20.03 | 2,819,844      |
| February    | 21.85            | 19.63 | 20.43 | 2,524,006      |
| March       | 23.24            | 19.05 | 19.55 | 3,893,778      |
| April       | 21.78            | 19.56 | 21.33 | 2,917,546      |
| May         | 22.30            | 8.76  | 9.74  | 9,049,316      |
| June        | 12.34            | 9.63  | 10.97 | 9,314,665      |
| July        | 13.26            | 10.76 | 12.59 | 9,155,218      |
| August      | 13.00            | 11.12 | 11.43 | 7,441,613      |
| September   | 13.39            | 11.40 | 12.92 | 5,017,073      |
| October     | 13.20            | 11.82 | 12.28 | 3,057,261      |
| November    | 16.74            | 12.40 | 16.15 | 8,996,683      |
| December    | 18.52            | 16.12 | 17.72 | 9,013,871      |
| <b>2011</b> |                  |       |       |                |
| January     | 21.87            | 16.82 | 19.9  | 8,864,773      |
| February    | 23.17            | 19.40 | 22.0  | 11,950,584     |
| March 1-4   | 23.48            | 21.32 | 23.26 | 2,046,200      |

## PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2010 and the number of securities of the class issued at that price and the date on which the securities were issued.

| Class of Securities          | Issue Price<br>or Exercise Price<br>\$ | Number of Securities<br>Issued | Date of Issue     |
|------------------------------|--|--------------------------------|-------------------|
| Stock Options <sup>(1)</sup> | 10.155                                 | 100,000                        | January 29, 2010  |
| Stock Options <sup>(1)</sup> | 10.685                                 | 1,646,000                      | April 6, 2010     |
| Stock Options                | 9.42                                   | 170,000                        | May 25, 2010      |
| Stock Options                | 12.35                                  | 12,000                         | July 8, 2010      |
| Stock Options                | 12.69                                  | 21,000                         | August 18, 2010   |
| Stock Options                | 11.87                                  | 20,000                         | September 2, 2010 |
| Stock Options                | 12.58                                  | 25,000                         | October 14, 2010  |
| Stock Options                | 16.18                                  | 55,000                         | November 23, 2010 |

**Note:**

(1) Adjusted to reflect the two-for-one stock split completed in May 2010.

## ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at the date hereof, the Corporation does not have any securities in escrow or that are subject to a contractual restriction on transfer.

## DIRECTORS AND OFFICERS

The following table sets forth the name, province and country of residence of the officers and directors of the Corporation, their position and offices with the Corporation, the periods during which they have served as officers or directors of the Corporation and their principal occupations for the past five years. The term of office of each director will expire at the end of the next annual meeting of shareholders of Celtic.

| Name, Province and<br>Country of Residence              | Positions and Offices<br>with the Corporation                           | Principal Occupation<br>During the Past Five Years  |
|---|---|---|
| David J. Wilson <sup>(3)(4)</sup><br>Alberta, Canada    | President and Chief Executive Officer and Director since September 2002 | President and Chief Executive Officer of Celtic.  |
| Sadiq H. Lalani<br>Alberta, Canada                      | Vice President, Finance and Chief Financial Officer since October 2002  | Vice President, Finance and Chief Financial Officer of Celtic.  |
| Michael R. Shea<br>Alberta, Canada                      | Vice President, Land since December 2002                                | Vice President, Land of Celtic.   |
| Alan G. Franks<br>Alberta, Canada                       | Vice President, Operations since December 2002                          | Vice President, Operations of Celtic.   |
| William C. Guinan <sup>(3)</sup><br>Alberta, Canada     | Corporate Secretary and Director since April 2002                       | Partner, Borden Ladner Gervais LLP, a law firm.   |
| Robert J. Dales <sup>(1)(2)(4)</sup><br>Alberta, Canada | Director since April 2002   | President, Valhalla Ventures Inc. a private Alberta investment corporation, from January 1999 to the present. President, Desco Resources Inc., a capital pool company. President, Desco Energy Ltd., a corporation engaged in oil and gas exploration and production from April 2005 to January 2007. |

| Name, Province and Country of Residence                           | Positions and Offices with the Corporation | Principal Occupation During the Past Five Years   |
|---|--|---|
| Eldon A. McIntyre <sup>(1)(2)(4)</sup><br>Alberta, Canada         | Director since September 2002              | President, Jarrod Oils Ltd., a private Saskatchewan corporation engaged in oil and gas exploration and production, from the late 1970's to the present. |
| Neil G. Sinclair <sup>(1)(2)(3)</sup><br>British Columbia, Canada | Director since April 2002                  | President, Sinson Investments Ltd., a private British Columbia corporation engaged in property development, from 1973 to the present.                   |

**Notes:**

- (1) Member of the Audit Committee. Celtic is required, pursuant to the ABCA, to have an audit committee of the board of directors.
- (2) Member of the Compensation Committee.
- (3) Member of the Disclosure Committee.
- (4) Member of the Reserves Committee.

As at March 7, 2010, the directors and officers of the Corporation, as a group, owned directly or indirectly 18,497,060 Common Shares or approximately 20.2% of the issued and outstanding Common Shares. The information as to the number of Common Shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

**Cease Trade Orders or Bankruptcies**

To the best of Celtic's knowledge, no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any corporation (including the Corporation) that: (a) while that person was acting in that capacity, was subject to a cease trade or similar order or an order that denied such corporation access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days; or (b) was subject to a cease trade or similar order or an order that denied such corporation access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days that was issued after that person ceased to act in such capacity and which resulted from an event that occurred while that person was acting in such capacity.

To the best of Celtic's knowledge, no director or executive officer of the Corporation, or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (a) is, as at the date of this Annual Information Form, or has been within the past 10 years, a director or executive officer of any corporation (including the Corporation) that while the person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the past 10 years before the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

**Penalties or Sanctions**

To the best of Celtic's knowledge, no director or executive officer of the Corporation, or shareholder of the Corporation holding sufficient securities of the Corporation to affect materially the control of the Corporation, has been subject to:

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

## **CONFLICTS OF INTEREST**

There are potential conflicts of interest to which the directors and officers of Celtic will be subject in connection with the operations of Celtic. In particular, certain of the directors and officers of Celtic are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Celtic or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Celtic. See "*DIRECTORS AND OFFICERS*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

## **LEGAL PROCEEDINGS**

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is or was a party to or of which any of its properties is or was the subject of, during the financial year ended December 31, 2010 nor are there any such proceedings known to the Corporation to be contemplated, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of the Corporation.

## **REGULATORY ACTIONS**

To the knowledge of the Corporation, there were no: (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the Corporation's last financial year; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority during the last financial year.

## **AUDIT COMMITTEE**

Under National Instrument 52-110 *Audit Committees*, the Corporation is required to include in its Annual Information Form the disclosure required under Form 52-110F1 with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix D attached hereto.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of any directors or executive officers of the Corporation, any person or company which beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares of the Corporation, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Corporation, or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation.

## **TRANSFER AGENT AND REGISTRAR**

The transfer agent and registrar for the Common Shares of Celtic is Valiant Trust Company at its principal offices in Calgary, Alberta.

## **MATERIAL CONTRACTS**

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by Celtic since its incorporation and still in effect as at the date hereof that can be reasonably regarded as presently material.

## **INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by Celtic during, or related to, the year ended December 31, 2010 other than Sproule, Celtic's independent qualified reserves evaluator and PricewaterhouseCoopers LLP, Chartered Accountants, Celtic's auditor. None of the designated professionals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Celtic or of Celtic's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. Celtic's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 6, 2011 in respect of Celtic's financial statements as at December 31, 2010 and 2009 and for each of the years ended December 31, 2010 and 2009. PricewaterhouseCoopers LLP have advised that they are independent with respect to Celtic within meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

## **ADDITIONAL INFORMATION**

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's Common Shares and options to purchase Common Share, is contained in the Corporation's management information circular relating to its most recent annual meeting of shareholders of the Corporation held on April 22, 2010. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2010, which may be found on SEDAR at [www.sedar.com](http://www.sedar.com).

Additional copies of this Annual Information Form, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation and any other document incorporated herein by reference will be available upon request by contacting the Vice President, Finance and Chief Financial Officer of the Corporation at its offices at Suite 500, 505 – 3<sup>rd</sup> Street S.W., Calgary, Alberta T2P 3E6, Telephone: (403) 201-5340 or Fax: (403) 201-9163.

## APPENDIX A

### Form 51-101F2

#### Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

#### Report on Reserves Data

To the Board of Directors of Celtic Exploration Ltd. (the "Company"):

1. We have evaluated the Company's Reserves Data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The Reserves Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves 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 "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

| Independent Qualified Reserves Evaluator or Auditor | Description and Preparation Date of Evaluation Report  | Location of Reserves (Country) | Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate) |                 |                |                |
|---|--|--------------------------------|---|-----------------|----------------|----------------|
|   |  |                                | Audited (M\$)   | Evaluated (M\$) | Reviewed (M\$) | Total (M\$)    |
| Sproule   | Evaluation of the P&NG Reserves of Celtic Exploration Ltd., As of December 31, 2010 prepared October, 2010 to February, 2011 | Canada                         |   |                 |                |                |
| <b>Total</b>  |  |                                | <b>Nil</b>  | <b>930,750</b>  | <b>Nil</b>     | <b>930,750</b> |

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.
6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited  
Calgary, Alberta  
February 3, 2011

(signed)

\_\_\_\_\_  
Cameron P. Six, P. Eng.  
Project Leader;  
Manager, Engineering and Associate

(signed)

\_\_\_\_\_  
Thomas Schenk, P.Eng.  
Petroleum Engineer

(signed)

\_\_\_\_\_  
Alec Kovaltchouk, P. Geol.  
Manager, Geoscience and Associate

(signed)

\_\_\_\_\_  
Harry J. Helwerda, P. Eng., FEC  
Executive Vice-President and Director

**APPENDIX B**  
**FORM 51-101F3**  
**REPORT OF**  
**MANAGEMENT AND DIRECTORS**  
**ON OIL AND GAS DISCLOSURE**

**Report of Management and Directors**  
**on Reserves Data and Other Information**

Management of Celtic Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) \_\_\_\_\_  
David J. Wilson  
President and Chief Executive Officer

(signed) \_\_\_\_\_  
Alan G. Franks  
Vice President, Operations

(signed) \_\_\_\_\_  
Robert J. Dales  
Director

(signed) \_\_\_\_\_  
Eldon A. McIntyre  
Director

Dated this 8th day of February, 2011.

## APPENDIX C

### DEFINITIONS USED FOR RESERVE CATEGORIES

The following definitions form the basis of the classification of reserves and values presented in the Sproule Report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM ("CIM"), incorporated in the Society of Petroleum Evaluation Engineers ("SPEE") Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and specified by National Instrument 51-101 ("NI 51-101").

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

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

#### 1. **Proved Reserves**

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.

#### 2. **Probable 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.

#### 3. **Possible 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. Possible reserves have not been considered in this report.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5 of the COGE Handbook.

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

#### 4. **Developed Reserves**

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 (e.g., 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.

## **5. Developed Producing 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.

## **6. Developed Non-Producing Reserves**

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.

## **7. Undeveloped Reserves**

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 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.

## **8. Levels of Certainty for Reported Reserves**

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

- (a) There is a 90% probability that at least the estimated proved reserves will be recovered.
- (b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.
- (c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

9. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.
10. **Company Gross Reserves** are the Company's working interest share of the remaining reserves, before deduction of any royalties.
11. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.
12. **Net Production Revenue** is income derived from the sale of net reserves of oil, pipeline gas, and gas by-products, less all capital and operating costs.
13. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.
14. **Barrels of Oil Equivalent (BOE) Reserves** - BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.
15. **Oil (or Crude Oil)** – a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.
16. **Gas (or Natural Gas)** – a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.
17. **Non-Associated Gas** – an accumulation of natural gas in a reservoir where there is no crude oil.
18. **Associated Gas** - the gas cap overlying a crude oil accumulation in a reservoir.
19. **Solution Gas** - gas dissolved in crude oil.
20. **Natural Gas Liquids** - those hydrocarbon components that can be removed from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

## APPENDIX D

### Form 52-110F1

#### Audit Committee Information Required in an AIF

##### 1. The Audit Committee's Charter

The following is the text of the Audit Committee's Charter.

##### I. PURPOSE

The primary function of the Committee is to assist the Board of Directors (the "Board") in fulfilling its oversight responsibilities by reviewing:

1. the financial information that will be provided to the shareholders and others;
2. the systems of internal controls, management and the Board have established; and
3. all audit processes.

Primary responsibility for the financial reporting, information systems, risk management and internal controls of the Corporation is vested in management and is overseen by the Board.

##### II. COMPOSITION AND PROCESS

1. The Committee shall be composed of a minimum of three directors, all of whom shall be independent as that term is defined in National Instrument 52-110 - *Audit Committees*.
2. Members shall be appointed by the Board on an annual basis, shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.
3. The Chair of the Committee shall be appointed by the Board for a one-year term, and may serve any number of consecutive terms.
4. All members of the Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.
5. The Chair shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Committee. The Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.
6. The Committee shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Committee shall be its Chair and one of its other members. The Committee may hold its meetings, and members of the Committee may attend meetings, by telephone conference if this is deemed appropriate.
7. The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee members with copies to the Board, the Chief Executive Officer, the Chief Financial Officer and the external auditor.

8. The Committee reviews, prior to their presentation to the Board and their release, all material financial information required by securities regulations.
9. The Committee enquires about potential claims, assessments and other contingent liabilities.
10. The Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

### **III. AUTHORITY**

1. The Committee is appointed by the Board pursuant to provisions of the *Business Corporations Act* (Alberta) and the bylaws of the Corporation.
2. Primary responsibility for the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board. The Committee is a standing committee of the Board established to assist it in fulfilling its responsibilities in this regard. The Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Committee to ensure that management has done so.
3. The Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.
4. The Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.
5. The Committee shall have the sole authority to retain (or terminate) advisors or consultants as it determines necessary to assist the Committee in discharging its functions hereunder. The Committee shall be provided with the necessary funding to compensate the advisors or consultants retained by the Committee.

### **IV. RELATIONSHIP WITH EXTERNAL AUDITORS**

1. An external auditor must report directly to the Committee.
2. The Committee is directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the issuer, including the resolution of disagreements between management and the external auditor regarding financial reporting.
3. The Committee shall implement structures and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

### **V. ACCOUNTING SYSTEMS, INTERNAL CONTROLS AND PROCEDURES**

1. The Committee shall obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates.
2. The Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.

3. The Committee shall review with the external auditor the quality and not just the acceptability of the Corporation's accounting principles and direct the external auditor's examinations to particular areas.
4. The Committee will review control weaknesses identified by the external auditors, together with management's response and review with external auditors their view of the qualifications and performance of the key financial and accounting executives.
5. In order to preserve the independence of the external auditor, the Committee will:
  - (a) recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation;
  - (b) recommend to the Board the compensation for the external auditors' engagement; and
  - (c) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact, if any, on the independence of the external auditor.
6. The Committee will review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting.
7. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
8. The Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under Multilateral Instrument 52-108 - Auditor Oversight.
9. The Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

## **VI. STATUTORY AND REGULATORY RESPONSIBILITIES**

1. Annual Financial Information - review the annual audited financial statements, including Letter to Shareholders and related press releases and recommend their approval to the Board, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.
2. Annual Report - review the management discussion and analysis ("**MD & A**") section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.
3. Interim Financial Statements - review the quarterly interim financial statements, including the Letter to Shareholders and related press releases and recommend their approval to the Board.
4. Earnings Guidance/Forecasts - review forecasted financial information and forward looking statements.
5. In addition, the Committee must review the Corporation's financial statements, MD & A and earnings press releases before the Corporation publicly discloses this information.

## VII. REPORTING

1. The Committee will report, through the Chairperson of the Committee, to the Board following each meeting on the major discussions and decisions made by the Committee, and report annually to the Board on the Committee's responsibilities and how it has discharged them.
2. In addition, the Committee will review and reassess these Terms of Reference annually and recommend any proposed changes to the Compensation Committee.

## VIII. OTHER RESPONSIBILITIES

1. Investigating fraud, illegal acts or conflicts of interest.
2. Discussing selected issues with corporate counsel or the outside auditor or management.

### 2. Composition of the Audit Committee

During the year ended December 31, 2010 the Audit Committee of the Corporation was composed of the following individuals:

|                |                            |                                     |
|----------------|----------------------------|-------------------------------------|
| Robert Dales   | Independent <sup>(1)</sup> | Financially literate <sup>(2)</sup> |
| Eldon McIntyre | Independent <sup>(1)</sup> | Financially literate <sup>(2)</sup> |
| Neil Sinclair  | Independent <sup>(1)</sup> | Financially literate <sup>(2)</sup> |

#### Notes:

- (1) A member of an audit committee is independent if the member has no direct or indirect material relationship with the Corporation which could, in the view of the Board, reasonably interfere with the exercise of a member's independent judgment.
- (2) An individual is financially literate if he has the ability to read and understand a set of financial statements that present a breadth of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

### 3. Relevant Education and Experience

Mr. Dales, the Chairman of the Audit Committee, holds an MBA. He also has over 16 years of public issuer experience, both as an officer and a director.

Mr. McIntyre has been President of an active private corporation, with significant oil and gas operations, for over 31 years. He also has over 18 years of public issuer experience as a director.

Mr. Sinclair holds a BA and an MBA. He has also been President of an active private corporation, with significant real estate operations, for over 31 years. He also has over 8 years of public company experience as a director.

### 4. Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on any exemption from National Instrument 52-110 ("NI 52-110"), other than in Section 2.4 of NI 52-110 (De Minimis Non-audit Services).

### 5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on the exemptions in Sections 3.3(2) or 3.6 of NI 52-110.

## 6. Reliance on Section 3.8

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on Section 3.8 of NI 52-110.

## 7. Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board.

## 8. Pre-Approval Policies and Procedures

The Audit Committee of the Corporation has adopted specific policies and procedures for the engagement of non-audit services entitled "Procedures for Approval of Audit and Non-Audit Services by the External Auditors" (the "**Procedure**"). Under the Procedure, the auditors may not act in any capacity where they function as management, audit their own work or serve in an advocacy role on behalf of the Corporation. Various audit related services provided by the auditors have been pre-approved. Management is required, however, to obtain pre-approval of the Audit Committee for services where engagement fees are expected to exceed \$25,000. Where fees for a particular engagement are expected to be less than or equal to \$25,000 the Chairman of the Audit Committee is to be notified expeditiously of the commencement of such services. If an engagement with the auditors for a particular service is contemplated that is neither expressly forbidden under the Procedure nor covered under the range of services provided for therein, such an engagement must be pre-approved. The Audit Committee has delegated the authority to effect such pre-approval to the Chairman of the Audit Committee. Pre-approved non-audit services shall be provided pursuant to an engagement letter signed by the auditors which shall set out the particular non-audit services to be provided. At every regularly scheduled meeting of the Audit Committee, management is required to report on all new pre-approved engagements of the auditors since the last such report.

## 9. External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation's external auditors in each of the last two fiscal years are as follows:

| <b>Year Ended<br/>December 31</b> | <b>Audit Fees<sup>(1)</sup></b> | <b>Audit-Related<br/>Fees</b> | <b>Tax Fees<sup>(2)</sup></b> | <b>All Other Fees</b> |
|-----------------------------------|---------------------------------|-------------------------------|-------------------------------|-----------------------|
| 2010                              | \$102,450                       | \$28,000                      | \$12,000                      | Nil                   |
| 2009                              | \$100,575                       | \$79,065                      | \$12,000                      | Nil                   |

### Notes:

(1) The aggregate audit fees billed.

(2) The aggregate fees billed for professional services rendered for tax compliance, tax advice and tax planning.