ANTRIM ENERGY INC.

Amended and Restated Annual Information Form

Year Ended

December 31, 2011

March 26, 2012

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Stb	stock tank barrel	MMcf	million cubic feet
Mbbl	thousands of barrels	Mcfpd	thousand cubic feet per day
bbl/d	barrels per day	MMcfpd	million cubic feet per day
NGL	natural gas liquids	m^3	cubic metres
LPG	liquefied petroleum gas	m^3/d	cubic metres per day

Other	
boe [(1)]	barrel of oil equivalent of crude oil and natural gas on the basis of 1 bbl of crude oil for 6 Mcf of natural gas
boe/d [(1)]	barrel of oil equivalent per day
bopd	barrel of oil per day
WTI	West Texas Intermediate
m	metres
km	kilometres
km^2	square kilometres

Note:

(1) boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In this Annual Information Form, all dollar amounts are expressed in United States ("**US**") dollars and all references to "dollars" or to "$" are to US dollars, all references to "Cdn $" are to Canadian dollars and all references to "£" are to British pounds sterling, unless otherwise specified.

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units) or vice versa.

To Convert From	To	Multiply By	To Convert From	To	Multiply By
Mcf	Cubic metres	28.317	Feet	Metres	0.305
Cubic metres	Cubic feet	35.315	Metres	Feet	3.281
Cubic metres	Barrels	6.289	Miles	Kilometres	1.609
Tonnes – butane	Barrels	12.45	Kilometres	Miles	0.621
Tonnes – propane	Barrels	10.94			

Forward Looking Statements

This AIF and any documents incorporated by reference herein contain certain forward-looking statements and forward-looking information which are based on Antrim's internal reasonable expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information. Forward-looking statements often, but not always, are identified by the use of words such as “seek”, “anticipate”, “believe”, “plan”, “estimate”, “expect”, “targeting”, “forecast”, “achieve” and “intend” and statements that an event or result “may”, “will”, “should”, “could” or “might” occur or be achieved and other similar expressions. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties, assumptions and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements and information. Antrim believes that the expectations reflected in those forward-looking statements and information are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements and information included in this AIF and any documents incorporated by reference herein should not be unduly relied upon. Such forward-looking statements and information speak only as of the date of this AIF or the particular document incorporated by reference herein and Antrim does not undertake any obligation to publicly update or revise any forward-looking statements or information, except as required by applicable laws.

In particular, this AIF and any documents incorporated by reference herein, contain specific forward-looking statements and information pertaining to the quality of and future net revenues from Antrim's reserves of oil, natural gas liquids (“NGL”) and natural gas production levels. This AIF may also contain specific forward-looking statements and information pertaining to the proposed plan of arrangement with Crown Point Ventures Ltd., commodity prices, foreign currency exchange rates and interest rates, capital expenditure programs and other expenditures, supply and demand for oil, NGL’s and natural gas, expectations regarding Antrim's ability to raise capital, to continually add to reserves through acquisitions and development, the schedules and timing of certain projects, Antrim's strategy for growth, Antrim's future operating and financial results, treatment under governmental and other regulatory regimes and tax, environmental and other laws and the start up of production from the Causeway, Fionn or Fyne fields in the UK North Sea.

With respect to forward-looking statements contained in this AIF and any documents incorporated by reference herein, Antrim has made assumptions regarding its ability to obtain additional drilling rigs and other equipment in a timely manner, obtain regulatory approvals, future oil and natural gas production levels from Antrim's properties and the price obtained from the sales of such production, the level of future capital expenditure required to exploit and develop reserves, the ability of Antrim’s partners to meet their commitments as they relate to Antrim and Antrim’s reliance on industry partners for the development of some of its properties. Antrim’s ability to obtain financing on acceptable terms, the general stability of the economic and political environment in which Antrim operates and the future of oil and natural gas pricing. In respect to these assumptions, the reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect.

Antrim's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks, including risks associated with the exploration for and development of oil and natural gas reserves, operational risks and liabilities that are not covered by insurance, volatility in market prices for oil, NGLs and natural gas, changes or fluctuations in oil, NGLs and natural gas production levels, changes in foreign currency exchange rates and interest rates, the ability of Antrim to fund its substantial capital requirements and operations, risks associated with the proposed plan of arrangement with Crown Point Ventures Ltd., including the risk that the transaction is not completed or is completed on different terms than those described herein, or the risk that certain rights of first refusal are exercised, and Antrim's reliance on industry partners for the development of some of its properties, risks associated with ensuring title to Antrim’s properties, liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing problems, the accuracy of oil and gas reserve estimates and estimated production levels as they are affected by the Antrim’s exploration and development drilling and estimated decline rates, in particular the future production rates at the Causeway and Fyne fields in the UK North Sea and at the Tierra del Fuego properties in Argentina. Additional risks include the ability to effectively compete for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel, incorrect assessments of the value of acquisitions, Antrim's success at acquisition, exploitation and development of reserves, changes in general economic, market and business conditions in Canada, North America, Argentina, South America, the United Kingdom, Europe and worldwide, actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws, royalty rates and incentive programs relating to the oil and gas industry and more specifically, changes to the capped market price in Argentina, changes in environmental or other legislation applicable to Antrim's operations, and Antrim's ability to comply with current and future environmental and other laws, adverse regulatory rulings, order and decisions and risks associated with the nature of the Common Shares.

Statements relating to "resources" are deemed to be forward-looking statements, as they involve the implied assessment based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. The estimates of remaining recoverable prospective resources have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Many of these risk factors, other specific risks, uncertainties and material assumptions are discussed in further detail throughout the AIF and in Antrim's management discussion and analysis for the year ended December 31, 2011. Readers are specifically referred to the risk factors described in this AIF under "Risk Factors" and in other documents Antrim files from time to time with securities regulatory authorities. Copies of these documents are available without charge from Antrim or electronically on the internet on Antrim's SEDAR profile at www.sedar.com. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The calculation of barrels of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas ("mcf") to one barrel of crude oil ("bbl"). Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead (as defined below).

In accordance with AIM guidelines, Mr. Kerry Fulton, P. Eng and Vice President, Operations for Antrim, is the qualified person that has reviewed the technical information contained in this AIF. Mr. Fulton has over 30 years operating experience in the upstream oil and gas industry.

THE COMPANY

General

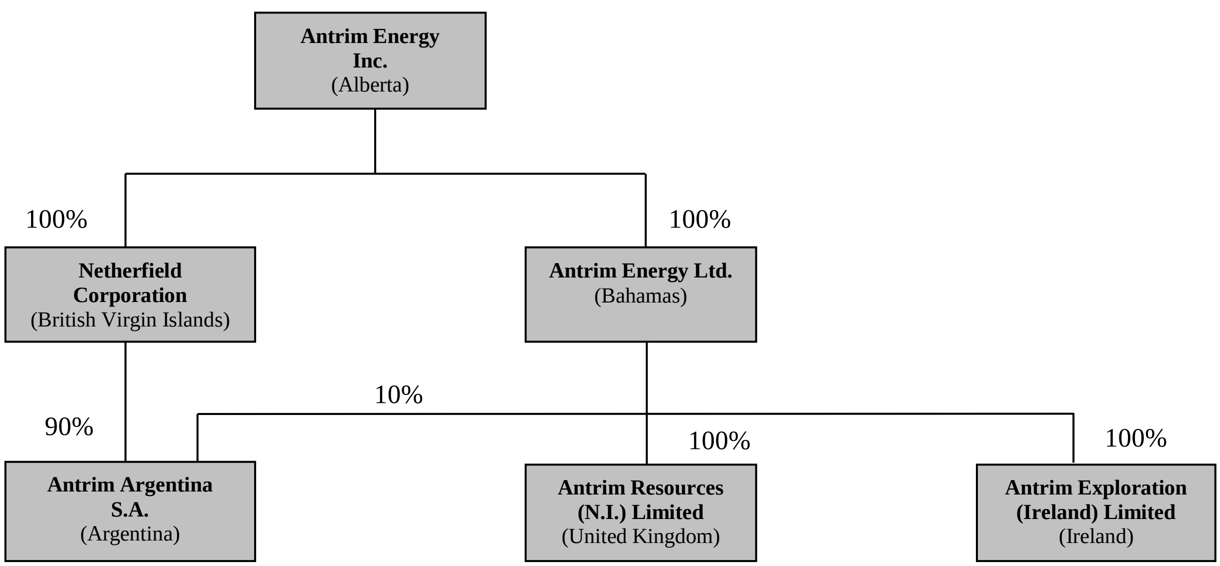
Antrim Energy Inc. ("**Antrim**" or the "**Company**") is a company engaged in the business of oil and natural gas acquisition, exploration, development and production in various international locations. Antrim was formed on the amalgamation (the "**Amalgamation**") of Antrim International Inc. and Netherfield Energy Corporation pursuant to Articles of Arrangement and Articles of Amalgamation filed under the Business Corporations Act (Alberta) on September 29, 1999. On October 12, 1999, the post-Amalgamation common shares ("**Common Shares**") of Antrim began trading on The Alberta Stock Exchange, a predecessor to the Canadian Venture Exchange ("**CDNX**") and now the TSX Venture Exchange. On February 2, 2001, Antrim began trading on The Toronto Stock Exchange (the "**TSX**") and subsequently delisted its securities from the TSX Venture Exchange. On July 31, 2003, the Common Shares were admitted for trading on the Alternative Investment Market operated by the London Stock Exchange plc ("**AIM**").

Antrim's properties are located in Argentina and United Kingdom. See "Business of Antrim" and "Statement of Reserves Data and Other Oil and Gas Information - Properties".

Antrim's principal business and head office is located at Suite 610, 301-8th Avenue S.W., Calgary, Alberta, Canada, T2P 1C5. Antrim's registered office is located at 1600, 333 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 2Z1.

Intercorporate Relationships

Antrim has five wholly-owned subsidiaries. The following chart sets forth the corporate structure of Antrim. The jurisdiction of incorporation is indicated in parentheses.



GENERAL DEVELOPMENT OF THE BUSINESS

Since incorporation, Antrim has focused on international oil and gas exploration and development. Antrim's current oil and gas interests are located in the United Kingdom and Argentina.

United Kingdom

Fyne and Dandy

Antrim acquired a 75% working interest in UKCS Licence P077 Block 21/28a (the **"Fyne Licence"**) in the Central North Sea in November 2006. The Fyne Licence contains the Fyne and Dandy oil fields, which had been delineated with eight wells drilled from 1971 to 1998. The cost of the acquisition was $8 million after closing adjustments. Antrim was appointed operator and agreed to pay the vendor an additional $10 million on approval of a field development plan ("**FDP**"). In June 2007, Antrim acquired 70 km^2 3D seismic.

In March 2008, drilling commenced on the Fyne Field. The Fyne drilling program targeted the Eocene Middle Tay Sandstone, which previously tested at rates up to 3,600 bopd of medium gravity (25° API) oil from the Fyne discovery well (21/28a-2), drilled and suspended in 1986. Antrim completed drilling operations on the Antrim-operated well 21/28a-9 on the Central Fyne Field in the UK Central North Sea in April 2008. The multilateral 21/28a-9 well was drilled as planned with three legs, one pilot hole and two sidetracks into the Eocene Tay Sandstone. All three holes encountered significant oil columns. The final sidetrack, 21/28a-9Y, was cased as a future production well with measured oil and gas pay thicknesses in the Tay Sandstone of 120 and 47 feet respectively.

In July 2008, appraisal drilling of well 21/28a-10 in the western lobe of the Fyne Field encountered 32 feet of net oil pay in the Tay Sandstone. Results from this well, combined with results from the previously drilled successful 21/28a-9Y well and sidetracks and the 21/28a-2 well, demonstrated reservoir and structural continuity across the field. In August 2008, further appraisal of the Fyne Field by well 21/28a-10Z, a planned sidetrack to 21/28a-10, encountered 60 feet of net oil pay in the Tay Sandstone. The well was successfully completed and tested at rates up to 4,000 bopd. An additional 45 feet of gas pay in the Upper Tay Sandstone remains untested.

In October 2010, Antrim signed an Earn In Agreement ("**EIA**") with Premier Oil UK Limited ("**Premier**") to jointly investigate development options for the Fyne area located in the UK Central North Sea. Under the terms of the EIA, Premier paid an initial consideration of $2 million to Antrim for an option to acquire a 39.9% interest in the Fyne Licence. As part of the transaction, Antrim transferred operatorship of the licence when Premier exercised their option to acquire the interest in the licence by drilling the East Fyne Well. In return, Antrim will receive up to a $50 million carry, less the initial consideration, towards its remaining working interest share of development costs of the Fyne field. Completion of the transaction is subject to several conditions, including Premier's commitment to submit an FDP to the Department of Energy and Climate Change ("**DECC**"). Following completion of the transaction, Antrim retained a 35.1% working interest in the Fyne Licence.

The agreement also provides Premier with the option to Farmin at 20% to 50% alongside Antrim in a planned drilling program in its surrounding licences (the "**Greater Fyne Area**", Antrim 100%) until such time as Premier elects not to proceed with the Fyne acquisition option. Premier exercised its option and participated in the drilling of the Erne well (21/29 11) and the second Erne well (21/29 11Z).

On February 6, 2012, the Company announced that the East Fyne appraisal well 21/28a-11, which commenced drilling on January 16, 2012, was plugged and abandoned. The well was designed to de-risk the eastern extent of the Fyne Field, however the thickness of the oil bearing sand was at the lower end of Antrim's estimate. Antrim is now incorporating the results of the East Fyne well into their reserve estimates and updating the field development options for the Fyne Field.

The original Fyne Licence expired on November 25, 2011. DECC agreed to a three-year extension to November 25, 2014 on the condition that an FDP for the Fyne Field is submitted by June 25, 2012. If the Fyne Field FDP is not submitted by that date, or an extension obtained from DECC, the Fyne Licence could be revoked. First production must be achieved from any of the three identified Prospective Areas (Fyne Field, Dandy Field and Area 4 Field) within the three year license extension period in order for that Prospective Area to become a Producing Area and the licence to continue. If first production is not achieved in a Prospective Area by November 25, 2014, the licence relative to that Prospective Area will expire. Although the Company expects to submit a Fyne Field FDP by June 25, 2012 and to achieve first production by 2014, there is no assurance that the Company will be successful in doing so.

Antrim identified the Fyne Field, the Dandy Field and the Area 4 Field as prospective areas, a total of 70.2 km^2 of the total 101.2 km^2 pre-renewal licence area. The remaining 30 km^2, which did not contain any production potential in the view of the Company, was relinquished effective November 21, 2010. Management expects to achieve first production in the Fyne Field by 2014 and in the Dandy Field and the Area 4 Field the following year.

The less than expected results of this well may have a material impact on the reserves and net present values presented in this report for the Fyne Field. Insufficient data exists at this time to properly assess whether there may be an impairment to the carrying amount of those assets. In addition, Premier is currently evaluating their project economics and retains the right to sell back the previously acquired 39.9% working interest at a nominal price.

UK 25th and 26th Seaward Licensing Round Properties

In November 2008, Antrim was notified by DECC that it had been offered three licences encompassing five new blocks in the UK North Sea in the 25th Seaward Licensing Round. The three licences were awarded to Antrim with 100% working interest in February 2009. Licences P1563 (Blocks 21/28b and 21/29c) and P1700 (Block 21/24c) are in the Company's core area of the Greater Fyne Area and Licence P1682 (Blocks 2/10a and 2/15b) is south of the Causeway area. An additional licence, P1625 (Block 21/24b) in the Greater Fyne Area, was awarded in June 2009, also with a 100% working interest. Licences P1700 and P1682 were promote licences with drill or drop decisions required by February 2011. Antrim relinquished these two licences in February 2011.

In October, 2010, Antrim was notified by DECC that it had been offered two licences encompassing two new blocks in the UK North Sea in the 26th Seaward Licensing Round with an effective date of January 10, 2011. Licence P1875 (Block 21/29d) is located in Antrim's core Greater Fyne Area, and was accepted by Antrim as a promote licence (Antrim 100%). The block falls within the joint venture area with Premier. A drill or drop decision is required at the end of the two year promote period. Licence P1784 (Block 21/7b) is also located in the Central North Sea and has been offered as a traditional licence (Antrim 30%). The licence was bid jointly with Premier (70%, operator) with a work plan comprising a firm well which is planned for Q3, 2012.

Antrim (50% and operator) drilled the Erne well 21/29d-11 on Block 21/29d with Premier (50%) in December 2011. The well encountered a hydrocarbon column in the Eocene Upper Tay Sandstone. The well intersected 30 feet of net oil and gas pay and the sidetrack encountered 38 feet of net oil and gas pay. The second Erne Well was also drilled in December 2011, encountering 24 feet of net oil pay and 12 feet of net gas pay. The sidetrack well has been suspended for possible use in the Fyne development plan.

Causeway

The area defined by Block 211/22a had been designated fallow under the UK's PILOT initiative that is a program designed to encourage new entrants and activities in the North Sea. A discovery well drilled in 1984 on the block (211/21a-3) tested oil at 5,512 bbls/d from a Jurassic reservoir.

In June 2004, Antrim announced the purchase of an 18.4% working interest in UKCS Licence P201 Block 211/22a South East Area. In November 2004 and January 2005, Antrim announced the purchase of additional working interests in the licence increasing its interest in January 2005 to 75.79%. In March 2005, Antrim announced that it had signed an agreement with a third party under which the third party would earn a 54.79% working interest in the north and western areas of the block in exchange for funding 100% of the cost of an exploration well on the block up to a gross cost of £5,750,000. Following the transaction, Block 211/22a was subdivided into Block 211/22a North West Area (Antrim 21%) and Block 211/21a South East Area (Antrim 79%). The southeast portion of the block included the prospective Osprey Ridge area situated in the East Shetland Basin of the North Sea. With subsequent farmouts, Antrim's working interest was reduced to 65.5%.

In 2006, Antrim was formally awarded UKCS Licence P1383 Block 211/23d as part of the United Kingdom 23rd Seaward Licensing Bid Round (Antrim 100%). With subsequent farmouts and exercise of rights of another company under an area of mutual interest agreement, Antrim's working interest was reduced to 65.5%, identical to P201 Block 211/22a South East Area. Together, the two licences (the "**Causeway Licences**") contain the "Causeway" oil field, a series of fault-bounded, staircase like structures extending northeast from Block 211/22a South East Area onto Block 211/23d. A discovery well drilled in 1992 on Block 211/23d, well 211/23b-11, tested oil at 8,100 bbls/d from the Jurassic Brent interval

In January 2006, Antrim was appointed as exploration operator of Block 211/22a South East Area and Block 211/23d. From June 2006 to October 2007, Antrim drilled five wells on the Causeway structure.

In June 2008, Antrim drilled the 211/23d-18 well in the East Causeway fault compartment and identified an oil column, including a new oil accumulation in the Etive Formation. This well was cased and will be used to provide pressure support to the 211/23d-17Z discovery well.

A summary of Antrim's 2006-2008 Causeway drilling program is as follows:

211/23d-17Z:	Tested at a peak rate of 14,500 bopd from the Tarbert and Ness formations
211/22a-6:	Tested at a peak rate of 6,300 bopd from the Ness and Etive formations
211/22a-7A:	Not tested but similar rates are expected to those measured in 22a-6 (6,300 bopd)
211/22a-8:	Tested 1,180 bopd from the Ness formation
211/22a-9:	Pressure support well for Central Causeway producers
211/23d-18:	Pressure support well for East Causeway producer

With the other wells on the Causeway structure that were tested prior to Antrim's entry into the licences (8,100 bopd and 5,500 bopd), cumulative test rates from the structure exceed 35,000 bopd with an expected additional 6,000 to 7,000 bopd from the untested 211/22a-7A well. An FDP was submitted to DECC in December 2008 with a phased programme starting with East and Far East Causeway. That FDP submission was suspended while waiting for further progress on an export route.

Effective December 8, 2009, 46.5 km^2 of the total 96.3 km^2 of the original Licence P1383 Block 211/23d was relinquished, as required after the initial four year term. The relinquished area was considered to have the lowest potential on the block, and does not include any of the delineated Causeway Field. UK North Sea Licence P1383 Block 211/23d has been extended into a second term, a period of four years.

In October 2011, Antrim completed a conditional letter agreement ("**CLA**") with Valiant Petroleum plc ("**Valiant**") to sell a 30% interest in the Causeway Licences. As part of the agreement, Antrim received a carry of up to $21.75 million towards their remaining working interest share of development costs of the Causeway Field. The environmental statement (ES) and the FDP was approved in December 2011.

As part of the transaction, Antrim transferred operatorship of the Causeway Licences to Valiant. Antrim retains a 35.5% working interest in the licences.

In November 2011, DECC agreed to separate field designations for the East and Far East Causeway fault compartments (now "Causeway") and the Central Causeway fault compartment (now "Fionn").

The operator (Valiant) has negotiated an export route with TAQA Bratani Limited ("**TAQA**") for use of the North Cormorant platform. Antrim and Valiant approved a phased development scheme for Causeway which is anticipated to come on to production in the third quarter of 2012 followed by Fionn in 2013. The FDP was approved by DECC in December 2011. Antrim is being carried by Valiant with respect to the Fionn Field and Antrim retains the option to back in after 3 months of production has occurred from Causeway. If Antrim does not elect to proceed with the Fionn development, its working interest in Fionn will be transferred to Valiant.

Kerloch and Contender

Antrim acquired a 21% working interest in UKCS Licence P201 (Block 211/22a) North West Area (the "**Kerloch Licence**") in 2005 as part of a division of Block 211/22a into two sub areas.

In October 2005, drilling commenced on the "Clachnaben" prospect, with Antrim being carried on a gross cost up to £5,750,000. The well was subsequently plugged and abandoned in December 2005 after drilling to the primary target.

In November 2007, Antrim participated in drilling the non-operated Kerloch prospect in the Kerloch Licence. The well was not flow tested; however, a comprehensive set of data including cores, wireline logs, reservoir pressure measurements and fluid samples was collected. The Kerloch well was suspended to allow potential re-entry and future use. The well discovered an oil column of approximately 116 feet in the Ness Formation and a number of oil samples were taken. No further drilling obligations exist on the Kerloch Licence.

In August 2011, Antrim signed a farm-out agreement with TAQA related to Kerloch Licence whereby TAQA agreed to drill an exploration well to earn an interest in the licence. Prior to the farm-out, Antrim held a 21% working interest in the licence.

In September 2011, DECC agreed to subdivide the licence into two sub-areas: the "Kerloch Area" in the north and the "Contender Area" in the south. By committing to drill an exploration well in the south, TAQA earned a 60% interest in the Contender Area. Antrim's working interest in the Contender Area was reduced to 8.4%. Once the exploration well is drilled, TAQA will earn 35% interest in the Kerloch Area. Antrim's remaining working interest in the Kerloch Area will be reduced to 13.65%.

TAQA assumed operatorship of the Contender Area and will drill the exploration well on the Contender Prospect from the Cormorant North platform. The well will target the Jurassic Brent sequence of sandstones at a projected drilling depth of 16,900 feet, less than two kilometres east of the Cormorant North Field. The well is expected to spud in the second quarter of 2012 and drilling will be funded by TAQA.

Argentina

Tierra del Fuego

In February 2005, Antrim completed the purchase of producing oil and natural gas assets in the Tierra del Fuego region in southern Argentina. The assets consist of a 25.78% working interest in three producing exploitation concessions including the Rio Cullen Concession, the La Angostura Concession and the Las Violetas Concession (the "**Tierra del Fuego Concessions**").

In 2005, the joint venture acquired approximately 358 km^2 of new 3D seismic data which identified a number of potential drilling targets on the concessions. In the fourth quarter of 2005, Antrim participated in a successful multi-well drilling program targeting reservoirs in the Cretaceous Springhill Formation in the Los Patos, Los Flamencos, Las Violetas, Rio Cullen areas, which continued until October 2006 when the rig contract expired. A total of nineteen wells were drilled during the program resulting in 9 gas wells, 7 oil wells, 2 shut in wells and 1 plugged and abandoned. In 2007, an additional 309 km^2 of new 3D seismic was acquired to allow the joint venture to identify both infield development locations and undrilled fault block exploration locations.

In September 2007, the joint venture commenced a two-year drilling program in Tierra del Fuego designed to add reserves and production from the Springhill Formation. The joint venture drilled 17 wells in 2008 in Tierra del Fuego, resulting in six (1.54 net) oil wells, five (1.29 net) gas wells, four (1.0 net) wells waiting on completion or other work and two (0.52 net) wells which were plugged and abandoned. During 2008, an additional 138 km^2 of 3D seismic were acquired over the Gaviotas and Puesto Quince prospects. In December 2008, the joint venture suspended further drilling in Tierra del Fuego, due to the current unfavorable economic conditions, and shifted its focus in Argentina to increasing production through tying in existing wells.

Drilling resumed in February 2010 with an eight month development program designed to increase gas and NGL production from the Springhill Formation in the Los Flamencos Field. Eight (2.1 net) of the ten wells were cased as producers of which three (0.8 net) had been tied in as of December 31, 2010. Of the remaining five (1.3 net) cased wells, four were fracture stimulated in the first half of 2011. Two of the four wells flowed gas and were placed on production, a third well tested oil and was placed on pump. The fourth well did not respond to fracture stimulation and was suspended. The fifth well was fracture stimulated in the third quarter of 2011 and placed on production. An additional well drilled in 2008 was re-entered and fracture stimulated and place on production in the third quarter of 2011. Two wells drilled in the 2010 drilling program were abandoned due to little or no reservoir being encountered. Subsequent mapping of the net gas pay in Los Flamencos reduced the estimated probable and possible reserves on the western part of the pool. Seven of the ten drilling locations in the 2010 drilling program had been previously classified as proved undeveloped in the independent reserve evaluation as of Dec 31, 2009 by McDaniel and the other three were classified as probable undeveloped. The eight successful wells in 2010 thus only resulted in a reclassification of reserves from "undeveloped" to "developed", and did not increase reserves overall.

The licences on the Tierra del Fuego Concessions expire in 2016. The operator is currently negotiating a ten year extension to the licences. Terms of the extension will include an upfront cash payment to the Province of Tierra del Fuego, an increase in royalties and a multi-well drilling commitment.

Antrim’s daily production in Argentina is expected to average approximately 1,600 boepd in 2012.

Cerro de Los Leones

On December 7, 2010, Antrim announced that it had entered into an agreement to acquire a 50.1% interest and operatorship of the 307,215 acre (153,915 acres net) Cerro de Los Leones concession located in the northern portion of the Neuquén Basin in the Province of Mendoza. The concession was acquired jointly with a publicly listed Canadian exploration and development company, and it is the intent of both parties to enter into a joint venture agreement to manage activities on the property.

The concession provides for a state royalty of 16% and carries an obligation to the government to acquire seismic data and drill up to five wells during a three year exploration period. The cost of the work commitment to the province is valued at $13.85 million (net to Antrim - $6.94 million). Antrim's interest in the block is being acquired from a private Argentine company. The terms of the acquisition include a reimbursement of approximately $1.0 million of exploration and permit expenses (net to Antrim - $0.5 million) and for the payment to the vendor of a 2.5% gross overriding royalty on any future production on the concession.

Antrim is currently working on obtaining the necessary environmental approvals to shoot a 3-D seismic program in the first half of 2012. Up to two exploration wells are planned for the latter part of 2012.

No reserves will be booked for Cerro de Los Leones prior to exploration drilling. Antrim's portion of the acquisition, seismic and drilling program will be fully funded utilizing cash and operating cash flow from the Company's existing Argentina operations.

Argentina Agreement

On March 26, 2012, Antrim and Crown Point Ventures Ltd. ("Crown Point"), an Argentine-focused oil and gas company listed on the TSX Venture Exchange, announced that they had entered into an arrangement agreement (the "**Arrangement Agreement**") whereby Crown Point will acquire all of the issued and outstanding common shares ("**Antrim Argentina Shares**") of Antrim's Argentina subsidiary, Antrim Argentina S.A ("**Antrim Argentina**"), which holds all of Antrim's Argentine oil and gas assets, by way of plan of arrangement under the *Business Corporations Act* (Alberta) (the "**Arrangement**").

Under the terms of the Arrangement, it is expected that Crown Point will directly or indirectly acquire all of the issued and outstanding Antrim Argentina Shares for a total consideration of approximately Cdn$53.75 million comprised of Cdn$10.26 million in cash (subject to certain adjustments) (the "**Cash Consideration**") and the issuance of 35,761,307 common shares of Crown Point ("**Crown Point Shares**") at a deemed price of Cdn$1.216 per Crown Point Share. Pursuant to the terms of the Arrangement, the Crown Point Shares will be distributed by Antrim to the holders of Common Shares on a pro rata basis as a return of capital.

Antrim's interest in its Tierra del Fuego Concessions is subject to certain rights of first refusal by third parties ("**ROFR**"). In the event that the ROFR is exercised, the consideration under the ROFR will be paid to Antrim, no distribution will be made to Antrim Shareholders and the Cerro de Los Leones property will be transferred to Crown Point for a fixed cash consideration which will be paid to Antrim on closing.

The Arrangement remains subject to certain regulatory approvals, including the approval of holders of at least two-thirds of the Antrim common shares, the approval of the Alberta Court of Queen's Bench, and the approval of the TSX Venture Exchange to the listing of the additional Crown Point Shares.

Antrim decided to divest of its oil and natural gas interests in Argentina to focus on higher return opportunities in the UK North Sea.

Ireland

In October 2011, Antrim was awarded a Frontier Licence Option ("**Option**") by the Department of Communications, Energy and Natural Resources of Ireland, under the Irish 2011 Atlantic Licensing Round.

The Licensing Option 11/5 area covers Blocks 44/4, 44/5 (part), 44/9, 44/10, 44/14, 44/15, an area of approximately 1,409 square kilometres and is located in the Porcupine Basin situated approximately 110 km off the SW coast of Ireland. The Option allows Antrim two years to qualify the blocks for a full Exploration Licence. Antrim has committed to a seismic work program of approximately $0.5 million.

Tanzania

In December 2010, two agreements were signed in Tanzania which are expected to lead to the resumption of exploration activities on the production sharing agreement for the Pemba-Zanzibar exploration licence offshore and onshore Tanzania (the "**P-Z PSA**"). Antrim holds an option to acquire a 20% interest in the P-Z PSA following the pre-drilling (seismic) phase and an additional 10% interest to be exercised up to 180 days following receipt of the initial drilling results. Carried costs associated with the interests would be repaid from future production. RAK Gas, the operator, has submitted a proposal for a revised work programme to the federal government of Tanzania, with seismic operations expected to proceed during 2012.

BUSINESS OF ANTRIM

Overview

Antrim is a Calgary, Alberta, Canada based energy company engaged in the acquisition, exploration, development and production of oil and natural gas in various international locations. Antrim's portfolio of assets includes exploration and development opportunities in Argentina and exploration and development opportunities in the United Kingdom. During the past year, Antrim's emphasis has been on development of the UK North Sea assets (Causeway and Fyne) to first production.

Antrim's present strategy is to grow through a combination of exploration, development and acquisition of oil and gas properties. Antrim also considers and reviews certain strategic opportunities as they arise from time to time. Antrim's approach to investment in international exploration is predicated on recommendations from its technical and commercial team. Most opportunities pursued are internally generated within Antrim. The Company's current philosophy is to fund Antrim's ongoing activities and project sourcing from internally generated cash flow and working capital to the extent possible. As exploration opportunities are recognized, Antrim will primarily access equity markets to fund seismic and drilling activities and a combination of equity and debt for development opportunities, provided such financing can be arranged on commercially acceptable terms. Acquisition opportunities could be financed from combinations of then-existing working capital, new equity issues and debt instruments, if available.

As mentioned elsewhere in this AIF, Antrim intends to divest its Argentina business to Crown Point pursuant to the Arrangement. If the Arrangement is implemented as planned, Antrim's shareholders will retain an interest in the Argentine assets as a result of the proposed distribution of Crown Point shares to Antrim's shareholders.

Operating Segments

All of Antrim's oil and gas revenue is currently from oil and gas properties in Argentina. Gross revenues, earnings (loss) and identifiable assets for each of Antrim's operating segments are set out in Note 20 to Antrim's 2011 audited consolidated financial statements filed on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com.

Marketing and Future Commitments

Argentina – Tierra del Fuego

All oil production from the "**Tierra del Fuego Concessions**" is currently sold on a spot basis to the domestic mainland market. The price received for crude oil sales is calculated based on the in-country Medanito crude oil benchmark price less a quality discount. Demand for and capacity to store crude oil within Tierra del Fuego is limited. Produced oil is stored and periodically transported by ship to a refinery on the mainland.

Prior to October 2007, all oil production from the Tierra del Fuego Concessions was exported via tanker truck to Chile. The export tax paid on crude oil exports at the time was 45% applied on the sales value after the tax. In November 2007, changes to the export tax were imposed with the objective of limiting the maximum price of oil that producers could receive for crude oil exports to $42 bbl. Despite this tax imposed ceiling price, higher mainland demand has resulted in increasing market prices for oil from late 2009 onwards.

NGL production from the Tierra del Fuego Concessions is both exported and sold domestically. Export sales are made to Empresa Nacional del Petróleo (ENAP) in Chile. In 2011, approximately 50.93% of butane and 35.33% of propane production was exported. The price for butane and propane is based on the Mont Belvieu Base price less a quality adjustment. The Mont Belvieu Base price is the price established for petroleum products at the spot market in Mont Belvieu, Texas. An export tax of up to 45%, dependent on world NGL prices, is applied to the sales value of NGL exports. The Secretariat of Energy decrees a portion of propane and butane production must be maintained for delivery to the local market In 2011, minimum propane deliveries for the concession were 700 tonnes/year at 995.5 pesos per tonne and 1000 tonnes / year at export parity price. Minimum butane deliveries for the concession to the local market were 2,794 tonnes [net 720 tonnes to Antrim] at 450 pesos from January to July and at 570 pesos from August to December. All butane and propane production in excess of the amount delivered to the local market in 2011 was sold in to the export market in Chile.

The Secretariat of Energy determined that a portion of Antrim's butane production must be provided to the mainland residential market. As butane produced in Tierra del Fuego has no physical access to mainland Argentina, Antrim fulfilled this obligation by a physical transfer arrangement with Yacimientos Petrolíferos Fiscales SA **("YPF")**. Under the terms of this agreement, Antrim delivers the butane to YPF terminals in Tierra del Fuego and then is provided an equivalent volume of butane for the mainland residential market supplied from gas processing facilities located in continental Argentina. In 2011, 2,562 tonnes were involved in the physical transfer arrangement.

Gas production from the "**Tierra del Fuego Concessions"** is sold to domestic residential and industrial consumers on Tierra del Fuego as well as to mainland Argentina under either month-to-month agreements or fixed-price contracts. Contracts vary with respect to fixed delivery requirements. Natural gas is delivered via the main pipeline that crosses the Strait of Magellan pipeline. Antrim and other gas producers were obligated by the government to invest in the twinning of this pipeline in 2009, through the purchase of interest bearing bonds issued by a national trust created by the government.

Effective September 1, 2007, Resolution 599 issued by the Secretary of Energy set out a minimum domestic market obligation for each producer to September 1, 2011. On January 5, 2012 Secretary of Energy issued Resolution 172 extending all terms and obligations of Resolution 599 until further notice. The average delivery obligation for the Tierra del Fuego Concessions, is 290,000 m3/d (net 74,762 m3/d to Antrim), or 10.241 MMcfpd (net 2.64 MMcfpd to Antrim). This gas is allocated between the residential, Compressed Natural Gas ("**CNG**"), thermal power and the industrial markets. The average delivery allocation to the residential market is 100,630 m3/d (net 25,942 m3/d to Antrim) or approximately 0.355 MMcfpd (net 0.091 MMcfpd net to Antrim) which is sold at a fixed price of approximately $0.507 per Mcf. The remaining allocated gas, 189,370 m3/d (net 8,819 m3/d to Antrim) or approximately 6.687 MMcfpd (net 1.724 MMcfpd to Antrim), was sold to the CNG, thermal and industrial island markets at an average price of $2.439 per Mcf in 2011. Under contracts in effect as of May 1, 2009, July 1, 2009, and February 2011, the volume of gas delivered to mainland industrial markets increased to 600,000 m3/d (net 154,682 m3/d to Antrim) or approximately 21.2 MMcfpd (net 5.5 MMcfpd to Antrim). Under the Petrobras contract (dated May 1, 2009), the price was $2.17 per mcf for 2011, the Albanesi contract (dated July 1, 2009) was $1.79 per mcf for 2011 whereas the Cammesa contract (dated February 2011) was $2.30 per mcf for 2011.

Gas sales contracts currently in place for 2012 delivery of gas to mainland industrial markets with Camessa are 220,000 m3/d (7.8 MMcfpd (net 2.01 MMcfpd to Antrim)), at $2.12/MMbtu (approximately $2.30/mcf) and Petrobras for 165,000 m3/d (6.0 MMcfpd (net 1.55 MMcfpd to Antrim)) at $2.40/MMbtu (approximately $2.61/mcf). Gas above these contract volumes is sold to Albanesi at a negotiable rate. The Gas Plus program has been approved by the Secretary of Energy, which is in the process of determining the sale price.

On all oil, NGL and gas sales, a provincial royalty is payable, less a deduction for allowable expenses which averages approximately 2.2%. The royalty rate on production is 10.8% plus an additional royalty of 1% for sales to the mainland (decreased from 2% as of April 2010). No corporate income tax is payable on net operating income from the Tierra del Fuego Concessions. For all products, Value Added Tax ("**VAT**") of 21% is charged on domestic sales destined to mainland Argentina and is retained by Antrim.

UK Income Tax Rate Increase

On March 23, 2011 the UK government announced an increase to the supplementary tax on UK oil and gas production from 20% to 32% effective March 24, 2011, thereby increasing the combined rate of tax on UK oil and gas production from 50% to 62%. The impact on Antrim is anticipated to be minimal over the next few years as Antrim has approximately $189 million in UK tax loss carry forwards which can be applied to reduce future taxable income.

Human Resources

As at December 31, 2011, the Company had 12 full-time employees based in Calgary, Alberta, 6 full-time employees based in Buenos Aires, Argentina and 1 full-time employee based in Guildford, Surrey, United Kingdom. The Company also utilized the services of several professionals on a part-time contract or consulting basis. Antrim seeks to employ individuals and utilize the services of consultants who have international oil and gas experience.

Competition

The oil and gas industry is highly competitive particularly as it pertains to the search for and development of new sources of crude oil and natural gas reserves, the construction and operation of crude oil and natural gas pipelines and facilities, and the transportation and marketing of crude oil, natural gas, sulphur and other petroleum products. Antrim's competitors include major integrated oil and gas companies and numerous other independent oil and gas companies, some of which have greater financial and other resources than Antrim. See "Risk Factors – Competition".

Environmental Protection

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, federal, regional, national, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions and discharges of various substances and materials (including wastes) produced in association with or otherwise arising from oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, decommissioned, abandoned and reclaimed in accordance with relevant laws and permits and including, where relevant, to the satisfaction of applicable regulatory authorities. Existing and possible future environmental legislation, regulations and actions could cause additional expense, capital expenditure, restrictions and delays in the activities of the Corporation, the extent of which cannot be predicted. See "Risk Factors – Government and Environmental Regulations" and "Risk Factors – Climate Change Impact".

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and procedures are in place to ensure utmost care is taken in the day-to-day management of its properties. The Corporation believes in well abandonment and site restoration in a timely manner to ensure minimal damage and overall costs to the Corporation. The Corporation makes full provision for the future cost of decommissioning oil production facilities and pipelines in Argentina and United Kingdom on a discounted basis on the installation of those facilities. At December 31, 2011, the estimated undiscounted asset retirement obligations of the Corporation are approximately $2.64 million and $5.79 million for Argentina and the United Kingdom, respectively. The Corporation expects the undiscounted obligations to be payable after 2015 for Argentina and after 2023 for the United Kingdom. The present value of the asset retirement obligations has been calculated using risk-free interest rates of 0.9% and 3.8% and inflation rates of 3.0% and 2.0% for Argentina and United Kingdom, respectively.

RISK FACTORS

Foreign Operations

Presently, all of Antrim’s oil and gas operations and assets are located in foreign jurisdictions. As a result, the Company is subject to political, economic and other uncertainties, including but not limited to changes, sometimes frequent and applied retroactively, in energy policies or the personnel administering them, nationalization, expropriation of property without fair compensation, cancellation or modification of contract rights, foreign exchange restrictions, currency fluctuations, royalty and tax increases, and other risks arising out of foreign governmental sovereignty over the areas in which the Company's operations are conducted, as well as risks of loss due to civil strife, acts of war, guerilla activities and insurrections. Changes in legislation may affect the Company’s oil and natural gas exploration and production activities. The Company's international operations may also be adversely affected by laws and policies of Canada as they pertain to foreign trade, taxation and investment.

In the event of a dispute arising in connection with its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada or enforcing Canadian judgments in foreign jurisdictions. In addition, Antrim's existing joint ventures and its subsidiaries were formed pursuant to, and their operations are governed by, a number of complex legal and contractual relationships. The effectiveness of and enforcement of such contracts and relationships with parties in these jurisdictions cannot be assured. Consequently, the Company's foreign exploration, development and production activities could be substantially affected by factors beyond the Company's control, any of which could have a material adverse effect on the Company.

Financing Requirements and Liquidity

It may take many years and substantial cash expenditures to pursue exploration activities on Antrim’s existing undeveloped properties. Accordingly, Antrim is likely to need to raise additional funds from outside sources in order to explore and develop its properties in a timely manner.

The Company’s financing risk relates to the availability and cost of equity or debt financing and is affected by many factors, including world and regional economic conditions, the state of international relations, the stability and the legal, regulatory, fiscal and tax policies of various governments in areas of operation, fluctuations in the world and regional price of oil and gas and in interest rates, the outlook for the oil and gas industry in general and in areas in which the Company has or intends to have operations, and competition for funds from possible alternative investment projects. Although there have been improvements in the global economy and financial markets in recent months, there continues to be restrictions on the availability of credit which may limit Antrim’s ability to access debt or equity financing for its development projects.

The Company may find it necessary in the future to obtain debt or additional equity to support ongoing operations, to undertake capital expenditures or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available to the Company when needed or on terms acceptable to Antrim. The Company's inability to raise financing to support ongoing operations or to fund capital expenditures or acquisitions could limit the Company's growth and may have a material adverse affect on the Company's business, financial condition, results of operations and cash flows.

Potential investors and lenders will be influenced by their evaluations of the Company and its projects, including their technical difficulty, and comparison with available alternative investment opportunities.

The Company continuously monitors its cash position, capital commitments and future capital requirements in order to ensure sufficient liquidity and capital resources are available. If adequate funds are not available, the Company will be required to scale back or even relinquish certain projects. If additional financing is raised by the issuance of shares from treasury, control of Antrim may change and shareholders may suffer dilution.

Strategic Transactions

As part of its development plan in the UK North Sea, the Company has implemented a strategic transaction with Premier. However, the closing of this transaction is subject to a number of conditions, some of which are beyond the control of Antrim. There is no assurance that the transaction with Premier will be closed, or if it is closed, that it will be closed on acceptable terms.

Risks Relating to the Arrangement with Crown Point

The completion of the Arrangement in the form contemplated by the plan of arrangement is subject to a number of conditions precedent, some of which are outside the control of Antrim, including, without limitation, receipt of Antrim shareholder approval and regulatory approvals (including approval of the TSX Venture Exchange for the listing of the Crown Point Shares issued as part of the Arrangement) and approval from the Alberta Court of Queen's Bench. There can be no certainty, nor can Antrim provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. The failure to obtain any such approvals will prevent Antrim from completing the Arrangement and may have a material adverse effect on the business and affairs of Antrim or the trading price of the Common Shares.

Antrim's interest in its Tierra del Fuego Concessions is subject to certain rights of first refusal by third parties (“ROFR”). In the event that the ROFR is exercised, the consideration under the ROFR will be paid to Antrim, no distribution will be made to Antrim Shareholders and the Cerro de Los Leones property will be transferred to Crown Point for a fixed cash consideration which will be paid to Antrim on closing.

Antrim and Crown Point are proposing to complete the Arrangement to strengthen the position of each entity in their respective core businesses and to realize certain benefits including, among other things, those set forth in the press release of Antrim dated March 26, 2012, which is available on SEDAR under Antrim's profile at www.sedar.com. There can be no assurances that Antrim or Crown Point will realize the anticipated benefits of the Arrangement.

Licensing and Title Risks

Antrim’s properties are generally held in the form of licences, concessions, permits and regulatory consents (“**Authorizations**”). Antrim’s activities are dependent upon the grant and maintenance of appropriate Authorizations, which may not be granted; may be made subject to limitations which, if not met, will result in the termination or withdrawal of the Authorization; or may be otherwise withdrawn. Also, in the majority of its Authorizations, the Company is a joint interest-holder with another third party over which it has no control. An Authorization may be revoked by the relevant regulatory authority if the other interest-holder is no longer deemed to be financially credible. There can be no assurance that any of the obligations required maintaining each Authorization will be met. Although the Company believes that the Authorizations will be renewed following expiry or granted (as the case may be), there can be no assurance that such Authorizations will be renewed or granted or as to the terms of such renewals or grants. The termination or expiration of the Company’s Authorizations may have a material adverse effect on the Company’s results of operations and business.

In addition, the areas covered by the Authorizations are or may be subject to agreements with the proprietors of the land. If such agreements are terminated, found void or otherwise challenged, the Company may suffer significant damage through the loss of opportunity to identify and extract oil or gas.

Title to oil and natural gas interests is often not determinable without incurring substantial expense. In accordance with industry practice, Antrim will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. The actual interest of Antrim in certain properties may vary from its records.

The original Fyne licence expired on November 25, 2011. DECC agreed to a three-year extension to November 25, 2014 on the condition that an FDP for the Fyne Field is submitted by June 25, 2012. If the Fyne Field FDP is not submitted by that date, or an extension obtained from DECC, the Fyne licence could be revoked. First production must be achieved from any of the three identified Prospective Areas (Fyne Field, Dandy Field and Area 4 Field) within the three year license extension period in order for that Prospective Area to become a Producing Area and the licence to continue. If first oil is not achieved in a Prospective Area by November 25, 2014, the licence relative to that Prospective Area will expire. Although the Company expects to submit a Fyne Field FDP by June 25, 2012 and to achieve first production by 2014, there is no assurance that the Company will be successful in doing so.

Loss from Operations

The Company has an accumulated deficit at December 31, 2011 of $168.0 million. No assurance can be given that the Company will not experience operating losses or write-downs of its oil and gas properties in the future.

Volatility of Crude Oil and Natural Gas Prices

Crude oil and natural gas are commodities that are sensitive to numerous worldwide factors, which are beyond the Company’s control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect Antrim’s results of operations and cash generated from operating activities. Consequently, such prices may also affect the value of the Company’s oil and gas properties and the level of spending for oil and natural gas exploration and development.

Antrim’s crude oil prices are based on various reference prices, primarily the WTI crude oil reference price and other reference prices such as UK Brent Light. Differentials in prices exist between WTI and UK Brent Light and can vary significantly over time. Adjustments are made to the reference price to reflect quality differentials and transportation. WTI and other reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries (“**OPEC**”) and political events. Occasionally quality differentials are affected by local supply and demand factors.

Any material declines in prices could result in a reduction of the Company’s net production revenue. The economies of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company’s reserves and the Company limiting or abandoning an exploration program on its undeveloped properties. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company’s net production revenue. All of the Company’s expenditures are subject to the effects of inflation and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation.

Reserves and Resource Risks

The reserve and resource data included herein are expressions of judgment based on knowledge, experience and industry practice. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenue there from are based upon a number of variable factors and assumptions, such as expected reservoir characteristics based on geological, geophysical and engineering assessments; ultimate reserve recovery; timing and amount of capital expenditures; future production rates based on historical performance and expected future operating and investment activities; future oil and natural gas prices and quality differentials; marketability of oil and gas; royalty rates; assumed effects of regulation by governmental agencies; and future development and operating costs, all of which may vary materially from actual results. It should not be assumed that estimated future net revenue is representative of the fair market value of the Company's properties. In addition, estimated reserves may change from time to time based on new or reprocessed information or new interpretations of existing or new information.

The resources estimates provided herein are estimates only. The estimate of resources includes contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be discovered.

Actual recovery may be less. The estimate of resources also includes prospective resources that have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Antrim transferred operatorship of Causeway to Valiant. The Company and Valiant obtained approval of the FDP from DECC in December 2011 with respect Causeway. With the approval of the FDP, Causeway reserves were transferred from probable to proved reserves. Antrim and Valiant's estimate of reserves differ in respect of the Fionn development. The Company expects that Valiant's estimates may be lower than those of Antrim as contained in the reserves report for Antrim dated March 26, 2012, prepared by McDaniel & Associates Consultants Ltd. ("**McDaniel**") and effective as of December 31, 2011 ("**The McDaniel report**").

Need to Replace Reserves

Antrim's future crude oil and natural gas reserves and production, and therefore its operating cash flows and results of operations, are highly dependent upon the Company's success in exploiting the current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, Antrim's reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability to make the necessary capital investments to maintain and expand the Company's oil and natural gas reserves will be impaired.

Oil and Gas Activities Involve Risks, Many of Which Are beyond Antrim's Control

The business of exploration and production of oil and gas involves a high degree of risk which a combination of experience, knowledge and careful evaluation, may not be enough to eliminate any amount of the risk. Few properties that are explored are ultimately developed into producing oil and gas fields.

The Company's rights to exploit its oil and gas assets are limited in time. There is no guarantee or assurance that such rights can be extended or that new rights can be obtained to replace any rights that expire.

Significant expenditure is required to establish the extent of oil and gas reserves through seismic surveys and drilling and there can be no certainty that oil and gas reserves will be found.

It is difficult to project the costs of implementing drilling programs 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 wells or additional seismic data and interpretations thereof.

Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some petroleum, are not sufficiently productive to justify commercial development or cover 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.

Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the availability of drilling and related equipment; the availability and proximity of pipeline capacity; the availability of processing capacity; the availability and productivity of skilled labor; the effects of inclement weather; unexpected cost increases; currency fluctuations; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; accidental events; and regulation of the oil and natural gas industry by various levels of government and governmental agencies. Because of these factors, the Company 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 hopes to produce.

Offshore Exploration

The Company faces additional risks when conducting offshore activities. In particular, drilling conditions, 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. Sub-sea tiebacks in the UK North Sea, while common, are also affected by weather conditions. Potential pipeline tie-backs can only be conducted from April to late September. Offshore oil and gas activities can also be affected by extreme weather and ocean phenomena arising from occurrences such as hurricanes and tsunamis.

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 areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. Antrim may be subject to relatively limited availability of offshore drilling rigs to proceed with a planned UK North Sea drilling program.

Access to Production Facilities and Pipelines

Access to facilities and pipelines to process field production is an important consideration when developing fields in the North Sea and Argentina. Such access is not guaranteed and directly affects the economics of a project. The United Kingdom government with the assistance of DECC has introduced a policy which has been adopted by the major operators of facilities in the North Sea that should allow access to facilities at a reasonable rate.

These types of initiatives are intended to ensure that reserves that cannot support facilities on a stand-alone basis can be developed.

Reliance on Key Personnel

The success of Antrim will be largely dependent upon the performance of its management and key employees. Failure by Antrim to retain or to attract and retain additional key employees with necessary skills could have a materially adverse impact upon Antrim's growth and profitability. Antrim has limited key person insurance for its management and none for other key employees. These individuals, and the contributions they will make, are important to the future operations and success of Antrim.

Reliance on Third Parties

To the extent Antrim is not the operator of its oil and natural gas properties, Antrim will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators including Valiant as it relates to their to obligations under the CLA and Premier as it relates to the EIA.

Conflicting Interests with Partners

Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with Antrim's interests and may conflict with Antrim's interests. Unless the parties are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated.

In certain circumstances, the concurrence of co-venturers may be required for various actions. Other parties influencing the timing of events may have priorities that differ from Antrim's, even if they generally share Antrim's objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect Antrim's strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect Antrim's participation in such projects or its ability to obtain or maintain necessary licences and other approvals.

Foreign Currency Rate Risk

A significant portion of the Company’s activities is transacted in or referenced to United States dollars, Canadian dollars, British pounds sterling or Argentine pesos. The Company’s operating costs and certain of the Company’s payments, in order to maintain property interests, are incurred in the local currency of the jurisdiction where the applicable property is located. As a result, fluctuations in the Canadian dollar, British pounds sterling and Argentine peso against the US dollar, and each of those currencies against any other local currencies in jurisdictions where properties of the Company are located, could result in unanticipated fluctuations in the Company’s financial results which are denominated in US dollars. The Company has not entered into any risk management contracts to hedge its exposure to foreign exchange rates.

Commodity Price Risk

From time to time Antrim may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Antrim would not benefit from such increases.

Marketability of Crude Oil and Natural Gas

The marketability and price of oil and natural gas produced and which may be acquired or discovered by the Company will be affected by numerous factors beyond the control of the Company. The Company will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil which are and may be produced by the Company. The ability of the Company to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of oil and natural gas, deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Cyclical and Seasonal Impact of Industry

Antrim’s operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by global supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. A decline in oil and natural gas prices could have an adverse effect on the Company's financial condition.

Competition

The oil and gas industry is highly competitive particularly as it pertains to the search for and development of new sources of crude oil and natural gas reserves, the construction and operation of crude oil and natural gas pipelines and facilities, and the transportation and marketing of crude oil, natural gas, sulphur and other petroleum products. Antrim’s competitors include major integrated oil and gas companies and numerous other independent oil and gas companies, some of which have greater financial and other resources than Antrim. The oil and natural gas industry is intensely competitive and the Company must compete in all aspects of its operations with a substantial number of other companies which have greater technical or financial resources. Substantially all of Antrim’s revenues are derived from oil and natural gas sales in Argentina to a small number of refiners and other consumers. There is no assurance that Antrim will be able to successfully compete against its competitors. However, Antrim strives to be competitive by maintaining a strong financial position and by using its network of international contacts and relationships to source and secure appropriate investment opportunities.

Government and Environmental Regulations

The petroleum industry is subject to regulation, enforcement and intervention by governments in such matters as the awarding and licensing of exploration and production interests, the imposition of specific drilling obligations, environmental protection and pollution controls, health and safety aspects of on and off-shore activity and operations, control over the development, decommissioning and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new legislation or regulations or the modification of existing legislation or regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil, increase costs and may have a material adverse impact on the Corporation. Export sales are subject to the authorization of provincial and federal government agencies and the corresponding governmental policies of foreign countries. Development of reserves and rates of return are also susceptible to changes in national fiscal policy. The current tax regime in the UK is favorable to companies of the Corporation's size in that it allows full deductions of appraisal and development expense before any tax is payable. As of January 1, 2006 the supplementary tax rate applicable to North Sea oil companies rose from 10% to 20%. This change resulted in an effective rate of corporation tax of 30% of profits after all capital and operating costs have been recovered, and an effective supplementary rate of 20% on profits after all capital and operating costs (excluding finance costs) have been recovered, resulting in an effective combined base and supplementary tax rate of no less than 50%. In 2009 a number of reforms were introduced to the North Sea fiscal regime aimed at fostering developments in smaller fields as well as more complex high pressure/high temperature and heavy oil fields. A small field relief of up to 10% of the 20% supplemental rate is granted in respect of fields of less than 25 mmbbls and so is potential benefit to the Corporation. Further favorable tax reforms were announced in January 2010 in which the additional tax allowances were extended to gas fields in frontier areas. On March 23, 2011, the UK government announced an increase to the supplementary tax on UK oil and gas production from 50% to 62%. Any changes to these laws would impact the net present worth of the Corporation's reserves. On March 21, 2012, The UK government announced that the maximum amount of the small field allowance introduced in Finance Act 2009 will be doubled from £75 million to £150 million. The qualifying criteria will also be relaxed. The maximum allowance will be available for fields which have reserves in place of 6.25 million tonnes (approximately 45 million barrels) or less, tapering to no allowance at 7 million tonnes (approximately 50 million barrels). The previous thresholds were 2.75 million and 3.5 million tonnes. For these purposes, a new field will be one with development authorization on or after 21 March 2012. The results of this change in the maximum allowance are expected to provide Antrim with additional tax benefits for the development of certain qualifying UK fields.

When originally introduced the maximum tax value of small field allowance was £15million, being £75million multiplied by the supplementary charge tax rate of 20%. By contrast the new allowance will be worth a maximum of £48million (£150 million at 32%) per relevant field.

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, federal, regional, national, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions and discharges of various substances and materials (including wastes) produced in association with or otherwise arising from oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, decommissioned, abandoned and reclaimed in accordance with relevant laws and permits and including, where relevant, to the satisfaction of applicable regulatory authorities. Existing and possible future environmental legislation, regulations and actions could cause additional expense, capital expenditure, restrictions and delays in the activities of the Corporation, the extent of which cannot be predicted. Before exploration and/or production activities can commence, the Corporation must obtain regulatory approval and relevant licences and there is no assurance that such approvals or licences will be obtained.

Environmental legislation and enforcement policy is evolving in a manner expected to result in more onerous and stricter requirements, standards and enforcement, larger fines and greater liability and potentially increased capital expenditures and operating costs. While the directors believe that the Corporation's current provision for compliance with environmental laws, regulations and liabilities (including decommissioning) in the countries in which it operates is reasonable, no assurance can be given that new rules and regulations will not be enacted or existing legislation, rules and regulations will not be applied in a manner which could limit or curtail the Corporation's production or development or result in increased liabilities. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of acquisition, exploration, development or production activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and procedures are in place to ensure utmost care is taken in the day-to-day management of its properties. The Corporation believes in well abandonment and site restoration in a timely manner to ensure minimal damage and overall costs to the Corporation.

Stage of Development

The Company may be subject to growth-related risks, capacity constraints and pressure on its internal systems and controls, particularly given the early stage of the Company's development. The ability of Antrim to manage growth effectively will require it to continue to expand its operational and financial systems and to train and manage its employee base. The inability of Antrim to deal with this growth could have a material adverse impact on its business, operations and prospects.

Strategic Partnerships

As part of its development plan in the North Sea, the Company may consider the formation of strategic partnerships, including those formed in 2010 with Valiant and Premier as it relates to the sharing of development costs and other similar interests in the Causeway and Fyne areas including, where appropriate, the acquisition or exchange of working interests. There is no assurance that any such strategic transaction will be entered into. If such strategic transaction is entered into, there is no assurance that such transaction will be successful.

Write-Off of Unsuccessful Properties and Projects

In order to realize the carrying value of its oil and gas properties and ventures, the Company must produce oil and gas in sufficient quantities and then sell such oil and gas at sufficient prices to produce a profit. The Company has a number of non-producing oil and gas properties. The risks associated with successfully developing such oil and gas properties are even greater than those associated with successfully continuing development of producing oil and gas properties, since the existence and extent of commercial quantities of oil and gas in unevaluated properties have not been fully established. The Company could be required to write-off some or all of its non-producing oil and gas properties if such projects prove to be unsuccessful.

Insurance

The Company's operations are subject to the risks normally associated with the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blowouts, cratering and fires, all of which could result in personal injuries, loss of life and damage to the property of the Company and others. In accordance with customary industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Damages and losses occurring as a result of such risks may give rise to claims against the Company.

Although the Company believes that it, or where applicable the operator, will carry adequate insurance with respect to its operations in accordance with industry practice, in certain circumstances the Company's, or where applicable the operator's, insurance may not cover or be adequate to cover the consequences of such events. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that is not covered or not fully covered by insurance, or the insolvency of the insurer of such event, could have a materially adverse effect on the business, financial condition and results of operations of the Company. Moreover, there can be no assurance that the Company will be able to maintain adequate insurance in the future at rates that it considers reasonable.

Regulatory Approvals

The further development of the Company's properties requires the approval of applicable regulatory authorities to the plans of the Company with respect to the drilling and development of such properties. A failure to obtain such approval on a timely basis or material conditions imposed by such authority in connection with the approval would materially affect the prospects of the Company.

Climate Change Impact

Antrim faces a variety of uncertainties related to climate change. The oil and gas industry is subject to extensive environmental regulation pursuant to legislation in the United Kingdom. These range from potential impacts from emissions restrictions, carbon taxes and other government policy initiatives, to changes in weather patterns that may affect operations. Although Antrim is not a large emitter of greenhouse gases, these forms of legislation may have an impact on both revenues and cost structures at a future undetermined time.

Acquisition Risks

Although the Company performs a review of properties prior to acquiring them that it believes is consistent with industry practice, such reviews are inherently incomplete. It is generally not feasible to review in depth every practice and every individual property involved in each acquisition. Generally, the Company will focus its due diligence efforts on higher valued properties and will sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. The Company may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interest in properties on an "as is" basis.

Force Majeure

The Company's projects may be adversely affected by risks outside the control of the Company including labor unrest, civil disorder, war, subversive activities or sabotage, fires, floods, explosions or other catastrophes, epidemics or quarantine restrictions.

Common Share Price Volatility

The market price of Antrim's common stock could be subject to wide fluctuations in response to Antrim's results of operations, changes in earnings estimates by analysts, changing conditions in the oil and gas industry or changes in general market, economic or political conditions.

Absence of Cash Dividends.

Antrim has not paid any cash dividends to date on the common stock and there are no plans for such dividend payments in the foreseeable future.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Company's Statement of Reserves Data and Other Oil and Gas Information dated March 20, 2012 and effective December 31, 2011 is attached as Schedule "A" hereto and is incorporated by reference in this Annual Information Form ("**AIF**").

PRINCIPAL OIL AND NATURAL GAS PROPERTIES

Properties

The following is a description of Antrim's principal oil and natural gas properties held as at December 31, 2011. The term "working interest", when used to describe Antrim's share of reserves, acreage or production, means the total of Antrim's net working interest share after deducting interests owned by others. Reserve amounts with respect to Antrim's interest in the Tierra del Fuego Concessions in Argentina and the Causeway and Fyne and Dandy Licence areas in the United Kingdom are stated as at December 31, 2011, net to Antrim based on forecast prices and costs as evaluated in the McDaniel Report dated March 26, 2012 prepared by McDaniel. See "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". Information in respect of gross and net acres, well counts and production are as at December 31, 2011 except where indicated otherwise. The company's statement of Reserve Data and Other Oil and Gas Information is effective December 31, 2011 and does not reflect the following:

Summary of Properties Table

Property (1)	**Operator**	**Working Interest %**	**Status and Licence Expiry Date(1)**	**Gross Licence Area (km^2)**
Argentina – Tierra del Fuego	Roch S.A.	25.78	Production	1,980.0
Argentina – Cerro de Los Leones	Antrim Argentina S.A.	50.10	Exploration	1,243.3
UK – Block 211/22a SE – Causeway, Fionn, West Causeway	Valiant Causeway Limited	35.50	Exploration and development	49.8
UK – Block 211/23d – Causeway	Valiant Causeway Limited	35.50	Exploration and development	63.6
UK – Block 21/28a – Fyne and Dandy	Premier Oil plc	35.10	Exploration and development	70.2
UK – Block 21/7b – Cyclone	Premier Oil plc	30.00	Exploration and development	175
UK – Block 211/22a NW – Kerloch Area	Dana Petroleum plc	21.00	Exploration	50.8
UK – Block 211/22a NW – Contender Area	Taqa Bratani Limited	8.4	Exploration	35.1
UK – Block 21/24b	Antrim Resources (N.I.) Limited	100.00	Exploration	145.7
UK – Block 21/28b and Block 21/29c	Antrim Resources (N.I.) Limited	100.00	Exploration	199.0
UK – Block 21/29d	Antrim Resources (N.I.) Limited	50.00	Exploration	109.7
Ireland – Block 44/1, 44/5 (partial), 44/9, 44/10, 44/14 and 44/15	Antrim Exploration (Ireland) Limited	100.00	Exploration	1,409

Note:

(1) See property description for licence expiry terms.

Argentina

Antrim's focus in Argentina is directed to what management considers to be, previously overlooked or unexploited proven oil and gas productive areas.

Tierra del Fuego

Antrim holds a 25.78% working interest in the Tierra del Fuego Concessions. The Rio Cullen, La Angostura and Las Violetas Concessions cover an area of approximately 490,000 acres, (126,322 net acres to Antrim). Each concession extends three kilometers offshore with their eastern boundaries paralleling the coastline. The concessions currently produce oil, gas and NGL. In 2011 there were **60 (15.5 net)** producing wells which produced an average of **1,061 bbl/d (261 bbl/d net)** oil, 234 bbl/d **(60 bbl/d net)** NGL, and **29 MMcfpd (7.5 MMcfpd net)** sales gas for the year ended December 31, 2011. In addition, **66 (17.0 net)** shut-in wells, **62 (16.0 net)** abandoned wells and **5 (1.3 net)** water injection wells are contained within the Tierra del Fuego Concessions. Oil, gas and NGLs are produced from lower Cretaceous Springhill Formation reservoirs. The Springhill Formation comprises sandstones laid down in a fluvial to shallow marine environment over an eroded low relief landscape. The sands are thickest in old erosional lows and thin or are absent over adjacent highs. Modern 3-D seismic is used to map the pre Springhill topography and identify areas where thicker sand developments can be expected. Post depositional tilting to the southwest coupled with northwest southeast trending normal faulting provides the predominant trapping mechanism for the Springhill reservoirs on the concessions. Drilling depths to the Springhill, range from 5,500 ft on the eastern portion of the concessions to 7,500 ft on the western edge.

The Tierra del Fuego Concessions are operated by Roch S.A. ("**Roch**"). Roch also holds a direct working interest in the concession. Antrim, Roch and other partners in the concession are party to a formal operating agreement dated February 18, 2005 (the "**Joint Operating Agreement**"). The Tierra del Fuego Concessions each have a term of 25 years that runs to 2016 with an option to extend the concessions for an additional ten year period with the consent of the government.

The operator is currently negotiating a ten year extension to the licences. Terms of the extension will include two upfront cash payments of $.74 (net) million each to the Province of Tierra del Fuego , an increase in royalties from 12% to 15% and a multi-well drilling commitment.

Currently, oil production from the concessions is transported by ship to a refinery on the mainland. NGL's (propane and butane) are both exported and sold domestically. Gas is sold to domestic residential and industrial consumers under fixed price contracts. A provincial royalty is payable on oil, gas and NGL sales, less a deduction for allowable expenses which averages approximately 2.2%. The royalty rate was 14% for the period of October 2008 to March 2010. Starting April 2010, the royalty rate was reduced to 13%. The royalty is calculated after a deduction for allowable expenses, which average approximately 2.2%. In February 2008, a gross revenue tax payable on domestic sales was increased from 2.0% to 2.5%. No corporate income tax is payable on net operating income from the Tierra del Fuego Concessions. Value Added Tax ("VAT") charged on domestic sales destined to mainland Argentina is retained by Antrim.

Drilling resumed in February 2010 with an eight month development program designed to increase gas and NGL production from the Springhill Formation in the Los Flamencos Field. Eight (2.1 net) of the ten wells were cased as producers of which six (1.6 net) had been tied in as of December 31, 2010. Two(.5 net) cased wells did not respond to fracture stimulation and were suspended. Two wells were abandoned due to little or no reservoir being encountered. Subsequent mapping of the net gas pay in Los Flamencos reduced the estimated probable and possible reserves on the western part of the pool. In addition to the decrease in probable undeveloped and possible undeveloped reserves due to the remapping in Los Flamencos, reserves in Tierra del Fuego were further reduced in the reserve report to reflect the volumes of oil, gas and condensate produced from the property in 2011.

In August 2009, Transportadora de Gas del Sur, in its capacity of transportation concessionaire and Manager of the pipeline extension project, commenced work on a project to build a second gas pipeline across the Strait of Magellan for the purpose of doubling gas deliveries from Tierra del Fuego. This project was completed in May 2010. Antrim and other gas producers were obligated by the government to invest in the twinning of this pipeline, through the purchase of interest bearing bonds issued by a national trust created by the government. Payment of the interest commenced in the first quarter of 2011 and repayment of the principle commenced in the third quarter of 2011.

Cerro de Los Leones

On December 7, 2010, Antrim announced that it had entered into an agreement to acquire a 50.1% interest and operatorship of the 307,215 acre (153,915 acres net to Antrim) Cerro de Los Leones concession located in the northern portion of the Neuquén Basin in the Province of Mendoza. The concession was acquired jointly with Crown Point Ventures Ltd., a publicly listed Canadian exploration and development company, and it is the intent of both parties to enter into a joint venture agreement to manage activities on the property.

The concession provides for a state royalty of 16% and carries an obligation to the government to acquire seismic data and drill up to five wells during a three year exploration period. The cost of the work commitment to the province is valued at $13.85 million (net to Antrim - $6.94 million). Antrim's interest in the block was acquired from a private Argentine company. The terms of the acquisition include a reimbursement of approximately $1.0 million of exploration and permit expenses (net to Antrim - $0.5 million) and for the payment to the vendor of a 2.5% gross overriding royalty on any future production on the concession.

Antrim is currently working on obtaining the necessary environmental approvals to shoot a 3-D seismic program in the second quarter of 2012. Up to two exploration wells are planned on the concession for the latter part of 2012.

No reserves will be booked for Cerro de Los Leones prior to exploration drilling.

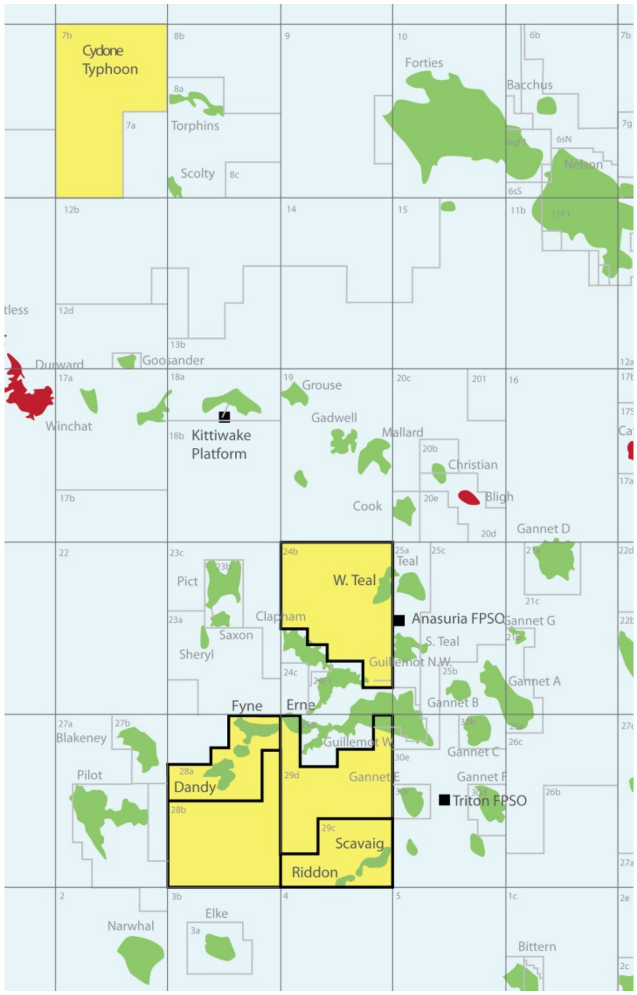
United Kingdom

Antrim has been active in the United Kingdom since 2004 with activities concentrated in the North Sea and Northern Ireland.

Antrim holds a 35.5% interest in the Causeway Licences, a 21% interest in the adjacent Kerloch Area Licence, 8.4% in the Contender Area Licence. Antrim currently has a farm-out agreement with TAQA relating to the Kerloch property whereby TAQA has agreed to drill an exploration well in the southern portion of the block (now called the Contender Area) to earn an interest in the licence. Upon completion of the well, TAQA will earn a 35% interest in the northern part (Kerloch Area), reducing Antrim’s interest to 13.65%. In addition, Antrim holds a 35.1% interest in the Fyne Licence and also holds a 100% interest in several licences adjacent to Fyne in the Greater Fyne Area (see map). These include Licences P1563 (Blocks 21/28b and 21/29c) immediately south-southeast of the Fyne Field, and P1625 (Block 21/24b), northeast of Fyne. These Greater Fyne Area licences were awarded in the 25th UK Licensing round.

Antrim acquired two additional licences in the most recent, 26th Seaward Licensing Round. Licence P1875 (Block 21/29d), east of Fyne), is 50% Antrim owned and operated. Licence P1784 (Block 21/7b) to the north of the Greater Fyne Area is 30% owned by Antrim. Premier holds the remaining 70% and is the operator. Licence documents for the 26th Seaward Licensing Round have an effective date of January 10, 2011.

UK North Sea– Greater Fyne Area



In October 2010, Antrim signed an EIA with Premier to jointly explore development options for the Fyne Area located in the UK Central North Sea. Under the terms of the EIA, Premier paid an initial consideration of $2 million to Antrim for an option to acquire a 39.9% interest in the Fyne Licence. As part of the transaction, Antrim transferred operatorship of the licence to Premier upon the exercise of their option to acquire a 39.9% interest in the licence. In return, Antrim will receive up to $50 million, less the initial consideration, towards its remaining working interest share of development costs of the field. Completion of the transaction is subject to Premier's commitment to submit a FDP to DECC. The parties are currently conducting an analysis of a development plan including the identification of viable export routes.

Following completion of the EIA transaction, Antrim retained a 35.1% working interest in the Fyne Licence. The agreement also provides Premier with the option to participate up to 50% alongside Antrim in a planned drilling program in its surrounding licences in the Greater Fyne Area. Discussions are currently in progress with owner/operators of several FPSOs for dedicated or cooperative use by Fyne. The Company's preferred production system will handle up to 20,000 bopd directly from the Fyne Field, with potential capacity add-ons to handle additional volume from the satellite fields.

The original Fyne Licence expired on November 25, 2011. DECC agreed to a three-year extension to November 25, 2014 on the condition that an FDP for the Fyne Field is submitted by June 25, 2012. If the Fyne Field FDP is not submitted by that date, or an extension obtained from DECC, the Fyne Licence could be revoked. First production must be achieved from any of the three identified Prospective Areas (Fyne Field, Dandy Field and Area 4 Field) within the three year license extension period in order for that Prospective Area to become a Producing Area and the licence to continue. If first production is not achieved in a Prospective Area by November 25, 2014, the licence relative to that Prospective Area will expire. Although the Company expects to submit a Fyne Field FDP by June 25, 2012 and to achieve first production by 2014, there is no assurance that the Company will be successful in doing so.

Antrim identified the Fyne Field, the Dandy Field and the Area 4 Field as prospective areas, a total of 70.2 km^2 of the total 101.2 km^2 pre-renewal licence area. The remaining 30 km^2, which did not contain any production potential in the view of the Company, was relinquished effective November 21, 2010. If any of the three identified prospective areas do not meet the first production criterion by November 2014, that given prospective area will be subject to relinquishment at that time. Management expects to achieve first production in the Fyne Field by early 2014 and in the Dandy Field and the Area 4 Field later in the year.

On February 6, 2012, the Company announced that the East Fyne appraisal well 21/28a-11, which commenced drilling on January 16, 2012, was plugged and abandoned. The well was designed to de-risk the eastern extent of the Fyne Field, however the thickness of the oil bearing sand was at the lower end of Antrim's estimate. Antrim is now incorporating the results of the East Fyne well into their reserve estimates and updating the field development options for the Fyne Field. The results of this well are likely to have a material impact on the reserves and net present values presented in this report for the Fyne Field. Insufficient data exists at this time to properly assess whether there may be an impairment to the carrying amount of those assets. In addition, Premier is currently evaluating their project economics and retains the right to sell back the previously acquired 39.9% working interest.

Antrim acquired its interest in the block in November 2006 and agreed to pay the seller of the block an additional $10 million on approval of the Fyne Field FDP.

UK North Sea 25thand 26th Seaward Licensing Round Properties - Greater Fyne Area

From February to June 2009, DECC awarded Antrim three licences in the UK 25th Seaward Licensing Round in the Greater Fyne Area: P1563 (Blocks 21/28b and 21/29c, traditional licence) with a bid comprising a firm well; P1625 (Block 21/24b, traditional licence) with a bid comprising a firm well, and; P1700 (Block 21/24c, promote licence). All were at 100% Antrim working interest. Licence P1700 was relinquished in February 2011 at the end of its two year promote period. Antrim is proceeding with plans to drill exploration wells on Licences P1563 and P1625 within their four year initial period.

The "West Teal" Fulmar prospect in Block 21/24b at 11,500 feet drilling depth is planned to be drilled in 2013, with an estimated cost of $24 million for drilling and $11 million for a sidetrack and a single drill stem test. The "Carra" Eocene Tay prospect in Block 21/28b at 5,000 feet drilling depth is also a primary drilling target, with an estimated drilling cost of $12 million. It is also planned to be drilled in 2013. Additional oil prospectivity occurs in the Riddon and Scavaig Discoveries, the Gill, Owel, Mask and Sillan prospects (all Tay Sands), the Jurassic Ree Lead and the Forties Lene Prospect.

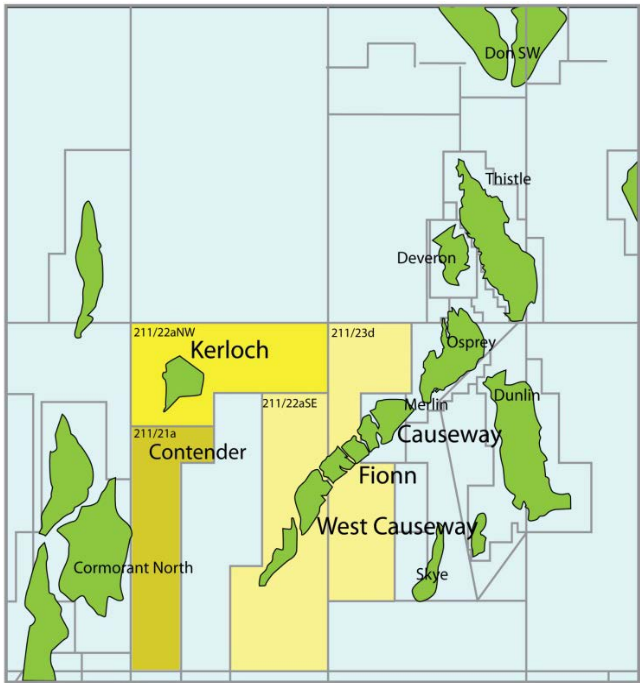
On October 28, 2010, Antrim announced that it had been notified by DECC that it had been offered two new licences covering two blocks in the UK North Sea in the 26th Licensing Round. Licence P1875 (Block 21/29d), east of Fyne, is 50% Antrim owned and operated, while P1784 (Block 21/7b) to the north of the Greater Fyne Area will be 30% owned by Antrim. Premier will hold the remaining 70% and will be the operator. Block 21/7b contains the Typhoon and Cyclone Prospects, both in Tertiary Cromarty Sands.

Block 21/29d is located in Antrim's core Greater Fyne Area in the Central North Sea, and is a promote licence (Antrim 100%). The block contains several exploration targets defined by 3-D seismic, including the "Erne" Eocene Tay Prospect at 5,200 feet drilling depth. The block falls within the joint venture area with Premier. Antrim and Premier jointly drilled the first Erne well (21/29d-11) in December 2011. The second Erne well (21/29d-11Z) was also successfully drilled in December 2011 and suspended for potential use in the Fyne Field development.

Licence P1784 Block 21/7b (Antrim 30%) is located in the Central North Sea north of the Greater Fyne Area. The block contains the "Cyclone" and the "Typhoon" Tertiary Cromarty prospects at approximately 5,000 and 5,600 feet respectively, in a region that is mature from both exploration and field infrastructure perspectives. The licence was acquired jointly with Premier (70%, operator) with a firm well commitment. An exploration well on the Cyclone Prospect has been approved by the joint venture partners and is planned to be drilled in the third quarter of 2012. The Typhoon Prospect would be a probable follow up to any discovery at Cyclone.

As part of the EIA with Premier on Fyne, Premier has the option to farmin at 20 to 50% on any of Antrim's 100% Greater Fyne Area Licences until such time as it elects not to proceed with the Fyne acquisition option.

UK North Sea Block 211/22a South East Area and UK North Sea Block 211/23d – Causeway



In March 2010, Antrim signed a CLA with Valiant to sell a 30% interest in Causeway. In return, Antrim received up to $21.75 million towards their remaining working interest share of development costs of the field.

As part of the transaction, Antrim transferred operatorship of the Causeway Licences to Valiant. Antrim retains a 35.5% working interest in the licences of P201 Block 211/22 South East and P1383 Block 211/23d.

Valiant has negotiated an export route for Causeway with TAQA that will use the Cormorant North Platform.

Antrim and Valiant approved a phased development with Causeway coming on to production in the third quarter of 2012 followed by Fionn, in 2013. The FDP was approved by DECC in December 2011. Antrim is being carried by Valiant with respect to the pre-development costs for the Fionn Field and Antrim retains the option to withdraw after 3 months of production has occurred from Causeway.

UK North Sea 25th Seaward Licensing Round Properties - Causeway Area

In the 25th Seaward Licensing Round, Antrim was awarded UKCS Licence P1682 Blocks 2/10a and 2/15b, situated approximately 40 kilometers southwest of the Company's existing Causeway, Kerloch and Contender properties (100% Antrim). These blocks were contiguous and subject to a single promote licence. Licence P1682 was relinquished in February 2011 at the end of its two year promote period.

UK North Sea Block 211/22a North West Area – Kerloch

Antrim acquired a 21% WI in the Kerloch Licence in 2005.

In November 2007, Antrim participated in drilling the non-operated Kerloch prospect in the Kerloch Licence. The well was not flow tested; however a comprehensive set of data including cores, wireline logs, reservoir pressure measurements and fluid samples was collected. The Kerloch well has been suspended to allow potential re-entry and future use. The well discovered an oil column of approximately 116 feet in the Ness Formation and a number of oil samples were taken. Antrim retains a 21% working interest in this portion of the block. No further drilling obligations exist on the block and the block is not eligible for fallow status until 2012.

On Aug 25th, 2011, Antrim announced that it had reached a farm-out agreement with TAQA relating to UKCS Licence P201 Block 211/22a North West Area (Antrim 21%). In September 2011, DECC agreed to subdivide the licence into two sub-areas: the Kerloch Area in the north and the Contender Area in the south. By committing to drill an exploration well in the south, TAQA earned a 60% interest in the Contender Area. Antrim's working interest in the Contender Area was reduced to 8.4%. Once the exploration well is drilled, TAQA will earn 35% interest in the Kerloch Area. Antrim's remaining working interest in the Kerloch Area will be reduced to 13.65%.

TAQA assumed operatorship of the Contender Area and will drill the exploration well on the Contender Prospect from the Cormorant North platform. The well will target the Jurassic Brent sequence of sandstones at a projected drilling depth of 16,900 feet, less than two kilometres east of the Cormorant North Field. The well is expected to spud in the second quarter of 2012 and drilling will be funded by TAQA.

Ireland

In October 2011, Antrim was awarded a Frontier Licence Option ("Option") by the Department of Communications, Energy and Natural Resources of Ireland, under the Irish 2011 Atlantic Licensing Round.
The Option area covers Blocks 44/4, 44/5 (part), 44/9, 44/10, 44/14, 44/15, an area of approximately 1,409 square kilometres located in the Porcupine Basin situated approximately 110 km off the SW coast of Ireland. The Option allows Antrim two years to qualify the blocks for a full Exploration Licence. Antrim has committed to a seismic work program of approximately $0.5 million.

Tanzania

In December 2010, two agreements were signed in Tanzania which are expected to lead to the resumption of exploration activities on the production sharing agreement for the Pemba-Zanzibar exploration licence offshore and onshore Tanzania (the "P-Z PSA"). Antrim holds an option to acquire a 20% interest in the P-Z PSA following the pre-drilling (seismic) phase and an additional 10% interest to be exercised up to 180 days following receipt of the initial drilling results. Carried costs associated with the interests would be repaid from future production. RAK Gas, the operator, has submitted a proposal for a revised work programme to the federal government of Tanzania, with seismic operations expected to proceed during 2012.

Material Contractual Obligations Associated with Properties

As of December 31, 2011 Antrim has the following material contractual commitments with respect to the Company's properties:

Argentina: Cerro de Los Leones – This exploration licence was acquired from an Argentine private company. The primary three year exploration phase requires Antrim and its partner to acquire 300km^2 3-D seismic and drill up to 5 wells. This work commitment is estimated at $13.85 million ($6.94 million net to Antrim). The primary exploration phase will begin when necessary environmental approvals to commence field work are issued by the provincial government. At the end of the primary three year exploration phase, there is a mandatory 50% relinquishment of the 1,243 km^2 concession.

United Kingdom:

P201 Block 211/22a South East Area - This licence is a 4th Round Licence and will expire in 2018. The FDP was approved in 2011 and includes a defined productive area around the Causeway Field, protecting it from any fallow designation.

P201 Block 211/22a North West Area - This licence is a 4th Round Licence and will expire in 2018. There are no work obligations outstanding. Further drilling must occur by 2013 and plans for production must be presented to protect it from fallow designation. The Contender well, planned for 2012, will satisfy this obligation.

P1383 Block 211/23d - This licence, which, in addition to block 211/22a South East Area, comprises the “Causeway area”, was awarded on a promote licence basis in 2005. As per the terms of the promote licence, a mandatory relinquishment of 46.5 km^2 of the original 96.3 km^2 of the licence was made in December 2009. The relinquished area was decreased to have the least potential on the licence, and does not include any of the delineated Causeway Field or the Fionn Field.

P1682 Blocks 2/10a & 2/15b– Antrim was required to purchase 500 km of 2D seismic and 50 km^2 of 3D seismic prior to February 2011. These commitments were fulfilled and the licence was relinquished in February, 2011.

P1563 Blocks 21/28b & 21/29c– Antrim was required to purchase and reprocess 70 km^2 of 3D seismic which was completed in 2010. An additional purchase of 55 km^2 and acquisition of 50 km^2 of 3D is required prior to year end 2013. Antrim is also committed to a contingent well on the licence by February 12, 2013. The remaining seismic obligation may be renegotiated if a well is drilled first.

P1700 Block 21/24c – Antrim was required to purchase and reprocess 17 km^2 of 2D seismic prior to year end 2010. This commitment has been fulfilled and the licence was relinquished in February 2011.

P1625 Block 21/24b – Antrim was required to acquire and reprocess 147 km^2 of 3D seismic prior to year end 2013. This commitment has been fulfilled in 2010. Antrim is also committed to a contingent well on the licence by June 20, 2013.

P1875 Block 21/29d – Antrim is required to acquire and reprocess 65 km^2 of 3D seismic prior to 2013. Antrim is also committed to drill a well on the licence by 2015. The Erne well 21/29d-11 satisfied this obligation.

P1784 Block 21/7b – Antrim is required to drill a well prior to 2015. The Cyclone well planned for 2012 will satisfy this obligation.

Ireland:

Licensing Option 11/5 Blocks 44/4, 44/5/partial, 44/9, 44/10, 44/14 and 44/15 – Antrim is required to complete a work program by 2013 that includes seismic procurement and reprocessing, design of a new 3D survey and nominal well, perform scoping economics, and mapping of leads and prospects.

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

The Statement of Reserves Data and Other Oil and Gas Information of Antrim Energy Inc. presented in Schedule "A" hereto uses reserves data presented by McDaniel in the McDaniel Report, which is incorporated by reference in this AIF.

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

The report of Antrim's management and directors on the oil and gas disclosure presented herein is attached as Schedule "C" hereto and is incorporated by reference in this AIF.

DIVIDEND POLICY

Antrim has not paid any dividends on its Common Shares to the date hereof. It is the present policy of the board of directors of Antrim to retain any earnings to finance the growth and development of Antrim's business and therefore Antrim does not anticipate paying any dividends in the immediate or foreseeable future.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of Antrim consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As at December 31, 2011, there were 184,102,745 Common Shares issued and outstanding. No Preferred Shares are issued and outstanding.

The following is a summary of the rights, privileges, restrictions and conditions attaching to each class of shares of Antrim.

Common Shares

The holders of Common Shares are entitled to: (i) receive notice of and to vote at every meeting of shareholders of Antrim and shall have one vote thereat for each such Common Share so held, (ii) receive any dividend declared on the Common Shares by Antrim subject to the rights of the holders of Preferred Shares; and (iii) subject to the rights, privileges, restrictions and conditions attached to the Preferred Shares, receive the remaining property of Antrim on dissolution, liquidation or winding up.

Preferred Shares

Preferred Shares may, from time to time, be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be fixed by the directors of Antrim. The directors may additionally determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares, including, without limiting the generality of the foregoing, the rate or amount of preferential dividends and the date of payment thereof, the redemption purchase and/or conversion price and conditions of redemption, purchase and/or conversion, if any, and any sinking fund or other provisions. The Preferred Shares rank in priority to the Common Shares as to payment of dividends and the distribution of assets in the event of dissolution, liquidation or winding-up.

Shareholder Rights Plan

At the 2010 annual meeting of shareholders, shareholders approved Antrim's Shareholder Rights Plan Agreement (the "**Rights Plan**") approved by the Board of Directors on May 27, 2010. Among other things, the Rights Plan was created to ensure, to the extent possible, that all shareholders of Antrim are treated fairly in connection with any take-over offer or bid for the common shares of Antrim, and to ensure that the Board of Directors is provided with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value.

The Rights Plan is not intended to prevent take-over bids. Under the Rights Plan, those bids that meet certain requirements intended to protect the interests of all shareholders are deemed to be permitted bids ("**Permitted Bids**"). Permitted Bids must be made by way of a take-over bid circular prepared in compliance with applicable securities laws and remain open for sixty days.

Under the Rights Plan, rights have been issued and attached to all common shares of the Company issued and outstanding as of the close of business on May 27, 2010. Rights will be issued upon any future issuance of any common shares of the

Company that occurs prior to certain events. On March 17, 2011, Antrim issued 48,191,700 common shares at a price of Cdn $1.07 per share.

MARKET FOR SECURITIES

The Common Shares of the Company are listed for trading on the TSX under the symbol "AEN" and on the Alternative Investment Market of the London Stock Exchange (AIM) under the symbol "AEY".

The following table sets out the high and low price for board lot trades and the volume of trading of the Common Shares on the TSX for the periods indicated.

	Price Range (Cdn $)		**Daily Average**
	High	**Low**	**Trading Volume**
2011			
January	1.24	.99	347,746
February	1.28	1.01	473,307
March	1.09	.89	363,745
April	1.17	.90	252,600
May	1.11	.88	270,479
June	1.16	.95	378,439
July	1.15	1.01	119,596
August	1.05	.81	172,241
September	.97	.78	107,049
October	1.12	.72	507,456
November	1.49	1,04	499,001
December	1.45	1.06	175.401
2012			
January	1.49	1.13	447,466
February	1.42	.96	396,113
March 1 to 23	1.18	1.01	412,692

DIRECTORS AND EXECUTIVE OFFICERS

The following table sets forth the names, municipalities of residence, positions with Antrim, time served as a director (if applicable) and the principal occupation during the last five years of the directors and executive officers of Antrim. Directors are elected at the annual meetings of shareholders and serve until the next annual meeting or until a successor is elected or appointed.

Name and Municipality of Residence	**Office Held**	**Principal Occupation During the Last Five Years**
Stephen E. Greer M.D. of Foothills, Alberta	President, Chief Executive Officer and Director since September 29, 1999.	Chief Executive Officer of Antrim.
Gerry Orbell(1)(3)(4)(5) West Sussex, England	Chairman of the Board of Directors and director since October 15, 2002.	Chairman and Chief Executive Officer, Sound Oil plc.
Jay Zammit(2)(5)(6) Calgary, Alberta	Director since May 12, 2004.	Partner, Burstall Winger LLP (Barristers and Solicitors)
Jim Perry(1)(3)(4)(5)(6) Calgary, Alberta	Director since February 15, 2005.	President and Chief Executive Officer, Alternative Fuel Systems (2004) Inc.

Name and Municipality of Residence	Office Held	Principal Occupation During the Last Five Years
Brian Moss Calgary, Alberta	Executive Vice-President, Latin America since July 28, 2008 and Director since April 7, 2006.	Executive Vice-President, Latin America of Antrim since July 2008. Prior thereto, from January 2008 consultant to Antrim. Prior thereto, Chief Operating Officer of Compass Petroleum Partnership ("**Compass**") from October 2007. Prior thereto President and Chief Executive Officer of Los Altares Resources Ltd. which was acquired by Compass.
Colin Maclean(2)(3)(4)(5) Edinburgh, Scotland	Director since May 20, 2008.	Independent director since November 2008. Prior thereto Business Unit Leader Refining, British Petroleum plc from January 1998 to January 2008.
James C. Smith(1)(2)(5)(6) Calgary, Alberta	Director since November 14, 2008.	Independent director to a number of public and private oil and gas companies.
Douglas B. Olson Calgary, Alberta	Chief Financial Officer since July 28, 2008.	Chief Financial Officer since July 2008. Prior thereto, Vice-President, Finance of CCS Income Trust from April 2006 to November 2007.
Kerry Fulton Calgary, Alberta	Vice President, Operations since October 1, 2008.	Vice-President Operations since October 2008. Prior thereto, Chief Operating Officer of Antrim.
Terry Lederhouse Calgary, Alberta	Vice President, Commercial since January 1, 2010.	Vice-President, Commercial since January, 2010. Prior thereto, Commercial Manager of Antrim.
Adrian Harvey Calgary, Alberta	Corporate Secretary since May 11, 2011	Associate, Burstall Winger LLP since, June 2010. Prior thereto, associate with Blake, Cassels & Graydon LLP.

Notes:

1. Member of the Audit Committee.
2. Member of the Compensation Committee.
3. Member of the Reserves Committee.
4. Member of the Exploration Committee.
5. Member of the Corporate Governance Committee.
6. Member of the Argentina Special Committee.
7. The Corporation does not have an Executive Committee.

As of December 31, 2011, the directors and executive officers of the Corporation as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,653,487 Common Shares or approximately 2.0% of the issued and outstanding Common Shares. In addition, the directors and officers of Antrim held options entitling them as a group to acquire an additional 5,820,000 Common Shares as of December 31, 2011.

Other than as set forth below, no director, executive officer of the Corporation or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, is as of the date hereof or was in the 10 years before the date hereof, a director or executive officer of any company (including Antrim) that while that person was acting in that capacity:

- was the subject of a cease trade order or similar order or an order that denied the company access to any exemption under applicable securities legislation, for a period of more than 30 consecutive days and which resulted from an event that occurred while that person was acting in the capacity as a director executive officer or after the director or executive officer ceased to be a director or executive officer, in the company; or

- 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.

On August 30, 2005, Jay Zammit became a director of Marine Bioproducts International Corp. ("**Marine**"), a company listed on the NEX Board of the TSX Venture Exchange Inc. that was the subject of a cease trade order in British Columbia and Alberta prior to Mr. Zammit's appointment. Mr. Zammit was appointed to the board to assist in the reinstatement of Marine to good standing. Marine successfully completed an equity financing on May 5, 2006 and on May 9, 2006, it successfully completed a Statutory Plan of Arrangement under the *Business Corporations Act* (Alberta) with Phoenix Oilfield Hauling Ltd., Alberta Loader Rentals Inc. and EMJ Consulting Ltd. (the "**Phoenix Group**") whereby Marine exercised options to purchase the Phoenix Group and whereby it changed its name to Phoenix Oilfield Hauling Inc. The cease trade orders against Marine were lifted on June 2, 2006. Mr. Zammit resigned as a director of Phoenix Oilfield Hauling Inc. on December 18, 2008. Phoenix is listed on the TSX Venture Exchange.

Jim Perry was the President, Chief Executive Officer and a Director of Alternative Fuel Systems Inc. and Mr. Jay Zammit was Corporate Secretary of Alternative Fuel Systems Inc. when it made an application under the *Companies' Creditors Arrangement Act* (Canada) (the "**CCAA**"). Alternative Fuel Systems Inc. completed a Statutory Plan of Arrangement under the CCAA and the Alberta Business Corporations Act on June 30, 2004 whereby the company was reorganized into two companies: Alternative Fuel Systems (2004) Inc. ("**AFS 2004**") and AFS Energy Inc. AFS Energy Inc. remains listed on the TSX Venture Exchange, completed a transaction to convert to an oil and gas company and changed its name to Flagship Energy Inc. (which now operates as Insignia Energy Ltd.) effective May 2005. AFS 2004 completed a private placement financing in 2005 and remained listed on the TSX Venture Exchange until being acquired by Fuel Systems Solutions Inc. in June 2011. Mr. Perry remains the President and Chief Executive Officer of AFS 2004 and is no longer associated with Flagship Energy Inc. or its successors. Mr. Zammit is now a director of AFS 2004 and is no longer associated with Flagship Energy Inc. or its successors.

Brian Moss acted as an independent director and chairman of Richards Oil & Gas Limited ("**Richards**") when Richards was issued cease trade orders by the ASC, BCSC, and OSC in May 2010, for failing to make required annual continuous disclosure filings for its 2009 financial year. Richards was granted protection from its creditors under the Bankruptcy and Insolvency Act (BIA) on May 5, 2010. Richard's shares were de-listed from the TSX Venture Exchange on July 9, 2010 for failure to pay corporate sustaining fees. Richards filed a proposal under the BIA on September 24, 2010 which was accepted by creditors and the Alberta Court of Queen's Bench on October 22, 2010. The ASC and OSC cease trade orders were varied in December 2010 to allow certain trades approved as part of the restructuring proposal. After assisting Richards with the completion of its restructuring process, Dr. Moss along with the rest of Richard's board of directors subsequently resigned on December 31, 2010.

No director, executive officer or proposed director of the Company or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, has, in the 10 years prior to the date hereof, 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 their assets.

No director, executive officer or proposed director of the Company or a shareholder holding a sufficient number of securities of Antrim to affect materially the control of Antrim, or any personal holding company of any such person, has been subject to 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 been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in making an investment decision.

Conflicts Of Interest

There are potential conflicts of interest to which the directors and officers of the Company or its subsidiaries may be subject in connection with the operations of the Company or its subsidiaries. Some of the directors and officers are engaged and will continue to be engaged, directly or indirectly, in other businesses and situations may arise where some of the directors and officers will be in direct competition with the Company or its subsidiaries. Jay Zammit, a director of the Company is a partner with Burstall Winger LLP, which provides legal services to the Company on a fee for services basis. Conflicts, if any, will be subject to the procedures and remedies under the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

The full text of the audit committee charter is included in Schedule "D" of this Annual Information Form.

Composition of the Audit Committee

The audit committee consists of three members, each of whom is financially literate and independent. The relevant education and experience of each audit committee member is outlined below.

James C. Smith

Mr. Smith is a Chartered Accountant with over 40 years of experience in public accounting and industry. Since 1998, he has been a business consultant to a number of public and private companies operating in the oil and gas industry. From 2002 until its sale in 2006, he was also the Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas company, and from 2001 until the sale of the company in 2003, was the Chief Financial Officer of Segue Energy Corporation, a private oil and natural gas company. From 1999 to 2000, Mr. Smith was the Vice President and Chief Financial Officer of Probe Exploration Inc., a publicly traded oil and natural gas company. While Mr. Smith was the Vice President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, the company completed an initial public offering, was listed on the TSX and completed several major debt and equity financing transactions. Mr. Smith is currently a director of Penn West Petroleum Ltd., Pure Energy Services Ltd. and Midway Energy Ltd.

Jim Perry

Mr. Perry is a graduate of the University of British Columbia, with a degree in Mineral Engineering. He is a Registered Professional Engineer in the Province of Alberta.

Mr. Perry served as Administrative Manager and Controller of the Schlumberger-Doll Research Center in Ridgefield, Connecticut from 1978 through 1979, during which time he was directly in charge of all accounting for a research laboratory with a staff of more than 100 people. He has served as President of a number of public companies, including Computalog Ltd., Global Thermoelectric Inc., and Alternative Fuel Systems Inc. In these positions, he directly supervised the Chief Financial Officer of each company.

Gerry Orbell

Mr. Orbell, B.Sc, Ph.D is currently Chairman and Chief Executive Officer of Sound Oil plc, a United Kingdom public company listed on the Alternative Investment Market of the London Stock Exchange. He has served as an executive director of a number of companies, including Premier Oil plc and United Utilities plc. For the last eight years Dr. Orbell has been Chairman of the Audit Committee of Valpak Ltd, an environmental compliance company in the UK.

Pre-Approval Policies and Procedures

Antrim has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The audit committee of the Board of Directors has established a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the audit committee, but at the option of the committee may cover a longer period. The list of services is sufficiently detailed as to ensure that (i) the audit committee knows what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services. All proposed services that have not already been pre-approved must be pre-approved by the audit committee.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2011 and 2010:

	2011	2010
Audit Fees	$ 244,414	$ 153,219
Audit-Related Fees (1)	80,410	60,171
Tax Fees (2)	80,434	34,122
All Other Fees (3)	41,041	18,958
Total	$ 446,299	$ 266,470

Notes:
(1) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as audit fees.
(2) Tax fees consist of fees for tax compliance services, tax advice and planning and transfer pricing studies
(3) All other fees consist of fees for internal controls review and advice on accounting standards.

LEGAL PROCEEDINGS

Antrim is not a party to nor is any of its property the subject of any legal proceedings nor, to the knowledge of management of Antrim, are any such proceedings known to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Company or any person or company that is the direct or indirect beneficial owner of or exercises control or direction over more than 10 percent of the Common Shares, or an associate or affiliate of any such person, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years of Antrim or during the current financial year that has materially affected or will materially affect Antrim.

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Common Shares and warrants of the Company.

MATERIAL CONTRACTS

Except as noted below, Antrim has not entered into any contract, other than contracts entered into in the ordinary course of business, that is material to Antrim and that was entered into within the most recently completed financial year or before the most recently completed financial year but is still in effect (other than contracts entered into before January 1, 2002).

On March 26, 2012, Antrim and Crown Point Ventures Ltd. ("**Crown Point**"), an Argentine-focused oil and gas company listed on the TSX Venture Exchange, announced that they had entered into the "**Arrangement Agreement**". See "General Development of the Business – Argentina – Argentina Agreement".

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 26, 2012 in respect of the Company's consolidated financial statements with accompanying notes as at and for the years ended December 31, 2011 and 2010. PricewaterhouseCoopers LLP have advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

McDaniel & Associates Consultants Ltd. is responsible for the report on the Company's reserves in Argentina and United Kingdom. McDaniel has advised that partners and associates of McDaniel had no direct or indirect beneficial interest in any securities or other property of the Company or its associates or affiliates at the time when such report was prepared, nor have they received after such time or are to receive any such interest. No director, officer or employee of McDaniel is or is expected to be elected, appointed or employed as a director, officer or employee of Antrim or any of its associates or affiliates.

ADDITIONAL INFORMATION

Additional information regarding the Company may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness to the Company, principal holders of securities of the Company and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular prepared in connection with the annual and special meeting of shareholders held May 26, 2011 (the "**Information Circular**"). Additional financial information is provided in the Company's comparative financial statements for its financial year ended December 31, 2011, together with the accompanying report of the auditor and management's discussion and analysis filed on SEDAR.

SCHEDULE "A" – FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF ANTRIM ENERGY INC.

Part 1 Date of Statement

Item 1.1 Date of Statement and Statement Information

This Statement of Reserves Data and Other Oil and Gas Information (the "**Statement**") is dated March 26, 2012. The effective date of the information provided in the Statement is December 31, 2011 unless otherwise indicated. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Part 2 Disclosure of Reserves Data

McDaniel has prepared the McDaniel Report, in which it has evaluated as at December 31, 2011 the oil and natural gas reserves attributable to the Company's Tierra del Fuego Concession in Argentina and the Causeway and Fyne and Dandy licence areas in the United Kingdom.

The McDaniel Report presents the estimated value of future net revenue from Antrim's properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by Antrim and/or the operator of its properties, which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by McDaniel in preparing the McDaniel Report and were accepted as represented without independent verification. In the absence of such information, McDaniel relied, with the approval of Antrim, upon its opinion of reasonable practice in the industry. All information provided to McDaniel was as at December 31, 2011 and, accordingly, certain of such information may not be representative of current conditions.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the forecast prices and costs contained in the McDaniel Report will be attained and variances could be material. The reserve and future net revenue estimates set forth below are estimates only and the actual reserves and realized net revenue may be greater or less than those calculated.

All dollar figures are presented in U.S. dollars which were used in the McDaniel Report.

Item 2.1 Reserves Data Using Forecast Prices and Costs

The following table discloses, by country and in the aggregate, the Company's gross and net proved and probable reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" means future prices and costs used by McDaniel in the McDaniel Report that are either generally accepted as being a reasonable outlook of the future, or fixed or currently determinable future prices or costs to which the Company is legally bound to deliver a physical product such as oil or natural gas.

	Antrim's Interest in Reserves(1)(2)(6)							
	Light and Medium Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**	
	Gross(3)	**Net(4)**	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
Argentina								
Proved:								
Developed Producing(5)	317	276	-	-	10,056	8,764	175	153
Developed Non-Producing	12	10	-	-	230	201	-	-
Undeveloped	252	220	-	-	7,700	6,711	70	61
Total Proved	581	506	-	-	17,987	15,676	245	214
Probable	379	330	-	-	10,642	9,274	84	73
Total Proved plus Probable	960	836	-	-	28,629	24,950	330	287

	Antrim's Interest in Reserves[1][2][6]							
	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]
United Kingdom								
Proved:								
Developed Producing[5]	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	721	627	-	-	-	-	-	-
Total Proved	721	627	-	-	-	-	-	-
Probable	11,885	11,885	-	-	-	-	-	-
Total Proved plus Probable	12,606	12,512	-	-	-	-	-	-
Total								
Proved:								
Developed Producing[5]	317	276	-	-	10,056	8,764	175	153
Developed Non-Producing	12	10	-	-	230	201	-	-
Undeveloped	973	846	-	-	7,700	6,711	70	61
Total Proved	1,301	1,133	-	-	17,987	15,676	245	214
Probable	12,264	12,215	-	-	10,642	9,274	84	73
Total Proved plus Probable	13,565	13,348	-	-	28,629	24,950	330	287

The following table discloses, by country and in the aggregate, the net present value of the Company’s future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

	Net Present Value of Future Net Revenue[1][2][6]									
	Before Income Taxes, discounted at %/year ($,000)					After Income Taxes, discounted at %/year ($,000)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Argentina										
Proved:										
Developed Producing	17,879	16,170	14,760	13,581	12,582	17,879	16,170	14,760	13,581	12,582
Developed Non-Producing	132	61	3	(44)	(84)	132	61	3	(44)	(84)
Undeveloped	14,901	11,377	8,770	6,804	5,296	14,901	11,377	8,770	6,804	5,296
Total Proved	32,912	27,608	23,532	20,340	17,794	32,912	27,608	23,532	20,340	17,794
Probable	31,300	23,285	17,724	13,766	10,883	31,300	23,285	17,724	13,766	10,883
Total Proved plus Probable	64,211	50,893	41,256	34,105	28,677	64,211	50,893	41,256	34,105	28,677
United Kingdom										
Proved:										
Developed Producing	-	-	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	5,412	4,772	4,091	3,414	2,764	5,412	4,772	4,091	3,414	2,764
Total Proved	5,412	4,772	4,091	3,414	2,764	5,412	4,772	4,091	3,414	2,764
Probable	453,514	369,253	303,449	252,110	211,870	346,327	286,508	238,713	200,788	170,663
Total Proved plus Probable	458,926	374,024	307,541	255,524	214,633	351,738	291,280	242,804	204,202	173,427

	Net Present Value of Future Net Revenue[1][2][6]									
	Before Income Taxes, discounted at %/year ($,000)					After Income Taxes, discounted at %/year ($,000)				
	0%	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Total										
Proved:										
Developed Producing	17,879	16,170	14,760	13,581	12,582	17,879	16,170	14,760	13,581	12,582
Developed Non-Producing	132	61	3	(44)	(84)	132	61	3	(44)	(84)
Undeveloped	20,313	16,149	12,861	10,218	8,059	20,313	16,149	12,861	10,218	8,059
Total Proved	38,323	32,379	27,624	23,754	20,558	38,323	32,379	27,624	23,754	20,558
Probable	484,814	392,538	321,173	265,876	222,752	377,626	309,793	256,437	214,554	181,546
Total Proved plus Probable	523.137	424,917	348,797	289,629	243,310	415,949	342,172	284,060	238,307	202,104

This table discloses, by production group, the net present value of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs and calculated using a 10% discount rate.

Production Group	Net Present Value of Future Net Revenue Before Future Income Tax Expense, Calculated using a 10% Discount Rate [1][2][6]			
	Proved Reserves		**Proved Plus Probable Reserves**	
	($,000)	**Unit Value ($)**	**($,000)**	**Unit Value ($)**
Light and Medium Oil	9,259	$7.12 / bbl	312,237	$23.02/ bbl
Heavy Oil	-	-	-	-
Natural Gas	16,164	$0.90 / Mcf	33,345	$1.16 / Mcf
Natural Gas Liquids	2,201	$8.98 / bbl	3,216	$9.76 / bbl
Total	27,624		348,797	

Notes:

(1) Totals may not add due to rounding.

(2) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.

(3) "Gross" reserves refer to Antrim's working interest share before deducting royalties and without including any of the Company's royalty interests.

(4) "Net" reserves refer to Antrim's working interest share after deducting royalties plus the Company's royalty interests. The royalties deducted from the reserves are based on the royalty percentage calculated by applying the applicable royalty rate or formula.

(5) All of the Proved Developed Producing Reserves evaluated in the McDaniel Report were on production at January 1, 2012.

(6) Future Income Tax Expenses includes "Abandonment Tax Relief" for the United Kingdom.

The following two tables provide additional information regarding the future net revenue attributable to total proved reserves outlined in the previous table.

This table discloses, by country and in the aggregate, certain elements of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs and calculated without discount.

Elements of Future Net Revenue Using Forecast Prices and Costs, Calculated without Discount[(1)(2)(6)(7)]	**Argentina ($,000)**	**United Kingdom ($,000)**	**Total ($,000)**
Proved Reserves			
Revenue	107,990	69,965	177,955
Royalties	15,225	-	15,225
Operating costs	43,081	17,091	60,172
Development costs	15,886	39,623	55,509
Abandonment and reclamation costs	886	7,839	8,725
Future net revenue before future income tax expenses	32,912	5,412	38,323
Future income tax expenses	-	-	-
Future net revenue after future income tax expenses	32,912	5,412	38,323
Proved Plus Probable Reserves			
Revenue	185, 881	1,270,261	1,456,142
Royalties	26,358	-	26,358
Operating costs	66,706	460,093	526,799
Development costs	27,436	290,337	317,773
Abandonment and reclamation costs	1,170	60,905	62,075
Future net revenue before future income tax expenses	64,211	458,926	523,137
Future income tax expenses	0	107,188	107,188
Future net revenue after future income tax expenses	64,211	351,738	415,949

Part 3 Pricing Assumptions

Item 3.1 Forecast Prices Used in Estimates

	Crude Oil Prices ($/bbl)						
Year	**WTI**	**Argentina-Tierra del Fuego (1)**	**Brent**	**UK Causeway**	**UK Fyne & Dandy**	**Natural Gas Price ($/ Mcf) Argentina Tierra del Fuego (2)**	**NGL Price ($/bbl) Argentina Tierra del Fuego (3)**
Antrim's actual weighted average for 2011		59.78		-	-	2.17	31.44
Benchmark reference price end of 2011	98.93		107.22	-	-		
Forecast							
2012	97.50	79.04	107.50	94.97	100.53	2.46	32.81
2013	97.50	79.04	102.60	89.82	95.84	3.02	32.81
2014	100.00	81.07	102.60	89.57	95.81	3.27	33.43
2015	100.80	81.72	103.50	90.21	96.63	3.43	33.63
2016	101.70	82.45	104.40	90.84	97.45	3.49	33.85
2017	102.70	83.26	105.50	91.67	98.46	3.54	34.10
2018	103.60	83.99	106.40	92.29	99.28	3.56	34.33
2019	104.50	84.72	107.40	93.01	100.19	3.54	34.55
2020	105.40	85.45	108.30	93.62	101.01	3.48	34.78

The escalating price and cost assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the McDaniel Report, future operating and capital costs are assumed to escalate at 2% per annum. McDaniel provided and used the following forecast price assumptions for Antrim's production in Argentina and United Kingdom:

Notes:

(1) Tierra del Fuego forecast oil price includes a 21% rebate on IVA tax.

(2) Tierra del Fuego gas price is a blend of various contracts. The price for gas shipped to mainland Argentina includes a 21% rebate on IVA tax. This price stream was extracted from the Total Proved plus Probable case from the McDaniel Report.

(3) Tierra del Fuego NGL price is a blend of butane and propane prices sold in Tierra del Fuego and to ENAP in Chile. The price for propane and butane sold to ENAP in Chile is reduced to account for an export tax. This price stream was extracted from the Total Proved plus Probable case from the McDaniel Report.

Part 4 Reconciliation Of Changes In Reserves And Future Net Revenue Reserves Reconciliation

Item 4.1 Reserves Reconciliation

The following table summarizes the changes during the year ended December 31, 2011 in Antrim's gross reserves in Argentina from its properties evaluated in the McDaniel Report, based on forecast prices and costs. See notes to preceding tables for information regarding forecast prices and costs.

	Argentina Light and Medium Crude Oil (Mbbl)			**Argentina Natural Gas (MMcf)**			**Argentina Natural Gas Liquids (Mbbl)**		
	Gross Proved	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**
Opening Balance (1)(2)(3)									
December 31, 2010	547	579	1,126	16,486	17,466	33,952	132	212	344
Plus:									
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	(30)	(41)	(71)	(1,312)	(1,252)	(2,564)	5	3	8
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Less:									
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	159	(159)	-	5,572	(5,572)	-	130	(130)	-
Production	(95)	-	(95)	(2,759)	-	(2,759)	(22)	-	(22)
Ending Balance – December 31, 2011	581	379	960	17,987	10,642	28,629	245	85	330

Notes:

(1) Totals may not add due to rounding.

(2) "Gross reserves" refer to Antrim's working interest share before deducting royalties. In the case of Argentina, an 11.8% provincial royalty is paid until the licence extension was assumed to be granted in mid-2012 and then provincial royalty increases to 14.3 percent thereafter.

(3) Reserves reconciliation in the AIF for the year ended December 31, 2011 was based on forecast prices and costs.

The following table summarizes the changes during the year ended December 31, 2011 in Antrim's gross reserves in the United Kingdom from its properties evaluated in the McDaniel Report, based on forecast prices and costs. See notes to preceding tables for information regarding forecast prices and costs.

	United Kingdom Light and Medium Crude Oil (Mbbl)			**United Kingdom Natural Gas (MMcf)**			**United Kingdom Natural Gas Liquids (Mbbl)**		
	Gross Proved	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Total Gross Proved plus Probable**
Opening Balance [1][2][3] December 31, 2010	-	27,726	27,726	-	-	-	-	-	-
Plus:	-			-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	-	(1,128)	(1,128)	-	-	-	-	-	-
Discoveries	721	(721)	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Less:									
Dispositions	-	(13,992)	(13,992)	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-
Ending Balance – December 31, 2011	721	11,885	12,606	-	-	-	-	-	-

Notes:

(1) Totals may not add due to rounding.

(2) "Gross reserves" refer to Antrim's working interest share before deducting royalties. No royalties are paid in the United Kingdom.

(3) Reserves reconciliation in the AIF for year ended December 31, 2010 was based on forecast prices and costs.

Part 5 Additional Information Relating To Reserves Data

Item 5.1 Proved Undeveloped and Probable Undeveloped Reserves

Proved undeveloped and probable undeveloped reserves have been attributed to Antrim's interests as of December 31, 2011 as follows.

Antrim's Interest in Undeveloped Reserves(1)(2) as of December 31, 2011

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Argentina								
Proved Undeveloped	252	220	-	-	7,700	6,711	70	61
Probable Undeveloped	157	137	-	-	4,813	4,195	38	33
Total Undeveloped	409	357	-	-	12,513	10,906	108	94
United Kingdom								
Proved Undeveloped	721	627	-	-	-	-	-	-
Probable Undeveloped	11,885	11,885	-	-	-	-	-	-
Total Undeveloped	12,606	12,512	-	-	-	-	-	-
Total								
Proved Undeveloped	973	846	-	-	7,700	6,711	70	61
Probable Undeveloped	12,044	12,024	-	-	4,813	4,195	38	33
Total Undeveloped	13,017	12,869	-	-	12,513	10,906	108	94

Proved undeveloped and probable undeveloped reserves were attributed to Antrim's interests as of December 31 of the previous three years as follows.

Antrim's Interest in Undeveloped Reserves(1)(2) as of December 31, 2010

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Argentina								
Proved Undeveloped	169	149	-	-	4,766	4,204	0	0
Probable Undeveloped	579	510	-	-	17,466	15,405	212	187
Total Undeveloped	748	659	-	-	22,232	19,609	212	187
United Kingdom								
Proved Undeveloped	-	-	-	-	-	-	-	-
Probable Undeveloped	27,726	27,726	-	-	-	-	-	-
Total Undeveloped	27,726	27,726	-	-	-	-	-	-
Total								
Proved Undeveloped	169	149	-	-	4766	4204	0	0
Probable Undeveloped	28,305	28,236	-	-	17,466	15,404	212	187
Total Undeveloped	28,474	28,385	-	-	22,232	19,609	212	187

Antrim's Interest in Undeveloped Reserves(1)(2) as of December 31, 2009

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Argentina								
Proved Undeveloped	278	246	-	-	9,226	8191	0	0
Probable Undeveloped	447	395	-	-	15,272	13,500	139	122
Total Undeveloped	725	641	-	-	24,538	21,691	139	122
United Kingdom								
Proved Undeveloped	-	-	-	-	-	-	-	-
Probable Undeveloped	27,726	27,726	-	-	-	-	-	-
Total Undeveloped	27,726	27,726	-	-	-	-	-	-
Total								
Proved Undeveloped	278	246	-	-	9,226	8,191	0	0
Probable Undeveloped	28,173	28,121	-	-	15,272	13,482	139	122
Total Undeveloped	28,451	28,367	-	-	24,498	21,673	139	122

Antrim's Interest in Undeveloped Reserves(1)(2) as of December 31, 2008

	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)	Gross(3)	Net(4)
Argentina								
Proved Undeveloped	265	234	-	-	7911	6,985	2	2
Probable Undeveloped	464	406	-	-	14,727	13,001	118	104
Total Undeveloped	729	640	-	-	22,638	19,986	120	106
United Kingdom								
Proved Undeveloped	-	-	-	-	-	-	-	-
Probable Undeveloped	26,245	26,245	-	-	-	-	-	-
Total Undeveloped	26,245	26,245	-	-	-	-	-	-
Total								
Proved Undeveloped	265	234	-	-	7,911	6,985	2	2
Probable Undeveloped	26,709	26,251	-	-	14,727	13,001	118	104
Total Undeveloped	26,974	26,885	-	-	22,638	19,986	120	106

Notes:

(1) Probable undeveloped reserve volumes for Argentina include volumes produced from probable undeveloped.

(2) Probable undeveloped locations and reserves for the U.K. include wells drilled but not yet completed and tied in.

(3) "Gross reserves" refer to Antrim's working interest share before deducting royalties. No royalties are paid in the U.K.

(4) "Net reserves" refer to Antrim's working interest share after deducting royalties. No royalties are paid in the U.K.

Argentina

Proved undeveloped reserves and probable undeveloped reserves were assigned to the Tierra del Fuego property based on geological mapping and engineering analysis of the existing pools, which incorporated drilling results and analysis of new 3D seismic data. These undeveloped reserves will be developed over the next three years. Changes to undeveloped reserves in Argentina in the Company's AIF for the year ended December 31, 2011 are attributable to Changes in performance of existing developed wells, and in re-allocations resulting from the assured licence renewal.

United Kingdom

Probable undeveloped reserves were assigned to the Fyne and Dandy property. The reserves were assigned based on the existing eight wells and three successful flow tests, the 3D seismic acquired and interpreted in 2007, and two multi-lateral wells drilled in 2008. These reserves will be developed over the next four years.

Probable undeveloped reserves were assigned to the four mapped fault blocks in Causeway, Fionn and West Causeway based on the successful drilling of six wells from 2006 to 2008, and the two previous wells which successfully tested oil. Three of the six wells drilled from 2006 to 2008 successfully tested oil. The other three wells were not production tested as sufficient information was already available from adjacent wells. These reserves will be developed over the next four years, with drilling to resume after oil production has started in the first phase of development.

Item 5.2 Significant Factors or Uncertainties

Estimates of oil and natural gas reserves and their values by petroleum engineers are inherently uncertain. Reserve estimates are based on evaluations of geological, engineering, production and economic data. These estimates are based on professional judgments about a number of elements and such professional judgments may vary as among different petroleum engineers. These estimates include:

- The amount of recoverable crude oil and natural gas present in a reservoir.
- The costs that will be incurred to produce the crude oil and natural gas.
- The rate at which production will occur.

The data can change over time due to, among other things:

- Additional development activity.
- Evolving production history.
- Changes in production costs, market prices and economic conditions.

As a result, the actual amount, cost and rate of production of oil and gas reserves and the revenues derived from sale of the oil and gas produced in the future will vary from those anticipated in the McDaniel Report as of December 31, 2011. The magnitude of those variations may be material.

All of Antrim's reserves are located outside of Canada. Accordingly, Antrim's reserve estimates are subject to additional risks and uncertainties. See "Business of Antrim – Risks of Foreign Operations".

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue set out under the headings "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data - Reserves Data Using Forecast Prices and Costs", by country and reserves category.

	Argentina		United Kingdom	
Year/Item	**Proved Reserves (forecast prices and costs) ($,000)**	**Proved plus Probable Reserves (forecast prices and costs) ($,000)**	**Proved Reserves (forecast prices and costs) ($,000)**	**Proved plus Probable Reserves (forecast prices and costs) ($,000)**
2012	6,287	6,855	39,623	56,274
2013	7,014	7,031	-	45,220
2014	1,162	9,632	-	126,722
2015	524	888	-	48,747
2016	251	741	-	13,374
remaining years	647	2,289	-	-
Total, undiscounted	15,886	27,436	39,623	290,337

Notes:

(1) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.

(2) See notes to tables under the headings "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data - Reserves Data Using Forecast Prices and Costs" regarding forecast prices and costs.

The Company expects that such funds will be obtained from combinations of existing working capital, internally-generated cash flow, new equity and debt instruments.

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Wells

The following table shows information regarding the Company's wells at December 31, 2011.

	Producing Wells[1]				Non-Producing Wells[1][5]			
	Crude Oil		Natural Gas		Crude Oil		Natural Gas	
	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]
Argentina	29	7.5	31	8.0	49	23.2	17	4.4
United Kingdom [4]	-	-	-	-	6	4.1	-	-
Total	29	7.5	31	8.0	55	27.3	17	4.4

Notes:
(1) The definitions of the various categories of reserves and wells are those set out in NI 51-101.
(2) "Gross wells are defined as the total number of wells in which Antrim has an interest.
(3) "Net" wells are defined as the total number of wells obtained by aggregating Antrim's working interest in each of its gross wells.
(4) Seven of the nine wells drilled in the U.K. in 2006, 2007, 2008 and 2011 are considered Non-Producing; the other two wells will be used for pressure maintenance.

Item 6.2 Properties with No Attributed Reserves

The following table sets forth information respecting Antrim's unproved properties as at December 31, 2011.

Country	Project	Working Interest (%)	Acreage	
			Gross[1]	Net[2]
United Kingdom	Block 211/22a NW Kerloch Area	21.0	12,550	2,635
	Block 211/22a NW Contender Area	8.4	8,670	728
	Block 21/24b	100.0	36,003	36,003
	Block 21/29d	50.0	27,095	13,548
	Blocks 21/28b & 29c	100.0	49,174	49,174
	Blocks 21/7b	30.0	43,225	21,613
Argentina	Cerro de Los Leones	50.10	489,268	245,123
Total			100,749	57,605

Notes:
(1) "Gross" acres are defined as the total area of properties in which Antrim has an interest.
(2) "Net" acres are defined as the total area in which Antrim has an interest multiplied by the working interest owned by Antrim.

McDaniel completed a resource assessment of the Kerloch Area Licence in Block 211/22a North West Area in 2007, following the drilling of well 211/22a-10. No additional independent evaluation has been performed. The results of McDaniel's November 2007 assessment were an assignment of Contingent Resources as follows [1] [2] [3] [4] [5].

Contingent Resources:

Property	1C Low Estimate Mbbl	2C Best Estimate Mbbl	3C High Estimate Mbbl
Kerloch	3,056	5,112	8,554
Net to Antrim	642	1,074	1,796

Notes:
(1) The definitions of the various categories of contingent resources are those set out in the Canadian Oil and Gas Evaluation Handbook:
- Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be

commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status.

- Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(2) All products are expected to be classified as Light and Medium Crude Oil.
(3) This estimate of contingent resources was based on a probabilistic analysis using a log normal distribution of the key input parameters, a methodology commonly used to estimate resources.
(4) The estimates of remaining recoverable contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be discovered. Actual recovery may be less.
(5) The effective date of the estimate of Contingent Resources is December 31, 2007. There has been no subsequent resource assessment.
(6) No flow test was conducted on well 211/22a-10, however cores, wireline logs, reservoir pressure measurements and fluid samples were taken. A considerable number of tests have been completed in a nearby and geologically comparable known accumulation, specifically in Antrim-operated Causeway wells 211/23d-17z, 211/22a-6 and 211/22a-8.
(7) The contingencies precluding the contingent resources for Kerloch from being classified as reserves are economic. There is no infrastructure currently available within a reasonable distance to Kerloch that will facilitate the economic development of the volume of resources assessed. Future development in the area could provide the required infrastructure to render a development at Kerloch economic.

Antrim completed an internal resources assessment of the blocks acquired in the 25th and 26th Seaward Licence Rounds in the area adjacent to and north of the Fyne Field: Blocks 21/24b, 21/29d, 21/28b, 21/29, 21/7b Based on that internal resources assessment, an assignment of Prospective Resources was made as follows [1] [2] [3] [4] [5] [6].

Prospective Resources:

Property	**Low Estimate Mbbl**	**Best Estimate Mbbl**	**High Estimate Mbbl**
Central North Sea	29,900	74,500	165,100
Net to Antrim	24,300	60,800	129,600

Notes:

(1) The definitions of the various categories of prospective resources are those set out in the Canadian Oil and Gas Evaluation Handbook:

- Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub classified based on project maturity.
- Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(2) All products are expected to be classified as Light and Medium Crude Oil.
(3) This estimate of prospective resources was based on a probabilistic analysis using a log normal distribution of the key input parameters, a methodology commonly used to estimate resources.

(4) The estimates of remaining recoverable prospective resources have been risked for chance of discovery, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.
(5) The Prospective Resources were estimated by Terry Lederhouse, P. Eng., Vice-President, Commercial of the Company. Mr. Lederhouse is a qualified reserves evaluator within the meaning of NI 51-101, but he is not independent in respect of the Company within the meaning of NI 51-101. The estimates were prepared in accordance with the procedures contained in the Canadian Oil and Gas Evaluation Handbook.
(6) The effective date of the estimate of Prospective Resources is December 31, 2011.
(7) There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources.

Item 6.3 Forward Contracts

The Company is not bound by an agreement (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas. See "Business of Antrim – Marketing and Future Commitments".

Item 6.4 Additional Information Concerning Abandonment and Restoration Costs

In deriving estimates for abandonment and restoration costs, the Company considered the geographic location of the wells and facilities in place as at December 31, 2011, the nature of the facilities and actual field experience.

Using this methodology, the Company's total unescalated abandonment and restoration costs, net of estimated salvage value, are estimated at $2,641,000 ($2,499,000 discounted at 0.9%) and $5,618,000 ($3,595,000 discounted at 3.8%) for Argentina and United Kingdom, respectively. It is estimated that this amount should cover costs for approximately 33.8 net wells in Argentina and 6.1 net wells in the United Kingdom plus similar costs for the Company's facilities and pipelines interests. All of the estimated abandonment and restoration costs were deducted in computing future net revenue. No portion of the Company's undiscounted total abandonment and reclamation costs expected to be paid in the next three financial years.

Item 6.5 Tax Horizon

The Company does not pay income taxes in Argentina. The Company does not expect to pay cash income taxes in Canada for at least the next five years.

Item 6.6 Costs Incurred

The following table summarizes in Canadian dollars certain expenditures of the Company as at Dec. 31, 2011.

	Property Acquisition Costs ($)				
Country	Unproved Properties	Proved Properties	Exploration Costs ($)	Development Costs ($)	Total ($)
Argentina	-	-	513,462	1,947,792	2,461,254
United Kingdom	-	-	17,512,539	20,781,525	38,294,064
Total	-	-	18,026,001	23,729,317	40,755,318

Note:
(1) The definitions of the various categories of properties and expenses are those set out in NI 51-101.

Item 6.7 Exploration and Development Activities

The following table sets forth the gross and net wells completed by Antrim during the financial year ended December 31, 2011.

Country	Oil Wells		Gas Wells		Service Wells		Dry Holes	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Argentina	0	0	0	0	0	0	0	0
United Kingdom	1	.5	0	0	0	0	2	.85

Country	Oil Wells		Gas Wells		Service Wells		Dry Holes	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Total	1	.3	7	1.8	0	0	2	.5

Notes:
(1) The definitions of the various categories of products and wells are those set out in NI 51-101.
(2) "Gross" wells are defined as the total number of wells in which Antrim has an interest.
(3) "Net" wells are defined as the total number of wells obtained by aggregating Antrim's working interest in each of its gross wells.

In 2012, the main activities of the Company in Argentina will be a 3-D seismic programme and an exploration well in Cerro de Los Leones, plus the start of a contingent drilling program in the Tierra del Fuego Concession contingent on the status of licence renewal negotiations. In the United Kingdom, the Company will progress the FDP's for the Fionn and Fyne Fields, and continue exploration drilling in the Greater Fyne Area and north of the Greater Fyne Area. The screening of opportunities for future projects will continue.

Item 6.8 Production Estimates

Estimated production volumes derived from the first year (2012) of the cash flow forecasts prepared in conjunction with the Company's proved and proved plus probable reserves data and included in the McDaniel Report are provided in the following table.

Summary of Production Estimates for 2012 (1)

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Proved								
Argentina	93	81	-	-	2,817	2,455	23	20
United Kingdom	320	264	-	-	-	-	-	-
Probable								
Argentina	4	4	-	-	109	95	-	-
United Kingdom	311	273	-	-	-	-	-	-
Total Proved + Probable	728	622	-	-	2,926	2,550	23	20

Notes:
(1) Estimated production from first year of proved plus probable producing reserves (forecast prices and costs) case in the McDaniel Report. The Tierra del Fuego in Argentina accounts for 100% of this production.
(2) "Gross" reserves refer to Antrim's working interest share before deducting royalties and without including any of the Company's royalty interests.
(3) "Net" reserves refer to Antrim's working interest share after deducting royalties plus the Company's royalty interests.

Item 6.9 Production History

The following table summarizes the Company's average daily production volumes (before deduction of royalties) and average prices, royalties and production costs in Canadian dollars on a quarterly basis during the financial year ended December 31, 2011.

Product Type/Item(1)(4)	Argentina Year Ended December 31, 2011				United Kingdom Year Ended December 31, 2011			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Light and Medium Crude Oil								
-average daily production volumes, before royalties (bbl/d)	234	269	176	262	-	-	-	-
-average price received ($/bbl)(2)	55.33	58.51	64.60	66.55	-	-	-	-
-average royalties paid ($/bbl)	8.95	8.09	10.21	10.45	-	-	-	-
-average production costs ($/bbl) (3)	7.95	9.35	11.22	8.07	-	-	-	-
-netback ($/bbl)	38.43	41.08	43.17	48.03	-	-	-	-
Natural Gas, Excluding NGL's								
-average daily production volumes, before royalties (Mcfpd)	7,834	7,318	7,403	7,304	-	-	-	-
-average price received ($/Mcf)	2.05	2.15	2.20	2.17	-	-	-	-
-average royalties paid ($/Mcf)	0.34	0.31	0.37	0.35	-	-	-	-
-average production costs ($/Mcf) (3)	1.12	1.53	1.34	1.46	-	-	-	-
-netback ($/Mcf)	0.60	0.31	0.49	0.36	-	-	-	-
Natural Gas Liquids								
-average daily production volumes, before royalties (bbl/d)	42	71	77	61	-	-	-	-
-average price received ($/bbl)	29.68	24.11	30.58	19.97	-	-	-	-
-average royalties paid ($/bbl)	5.82	4.06	6.21	3.80	-	-	-	-
-average production costs ($/bbl)	9.07	7.52	6.91	8.77	-	-	-	-
-netback ($/bbl)	5.11	2.58	4.88	(2.18)	-	-	-	-

Notes:
(1) Totals may not add due to rounding.
(2) The definitions of the various categories of products and expenses are those set out in NI 51-101. After export tax.
(3) Product prices are net of quality differential and costs to transport the product to market. Represents sales of light quality crude oil. During the periods indicated Antrim did not sell any medium, heavy or synthetic crude oil.
(4) This figure includes all field operating expenses.

The following table summarizes the Company's production volumes during the financial year ended December 31, 2011 for each important field and in total, by product type.

Field	Light and Medium Crude Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Tierra del Fuego	95	-	2,759	22
Total Production	95	-	2,759	22

SCHEDULE "B" – FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Antrim Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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 (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
		Audited	**Evaluated**	**Reviewed**	**Total**
March 26, 2012	Argentina	-	41,256	-	41,256
March 26, 2012	United Kingdom	-	307, 541	-	307,541

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

Calgary, Alberta
Date: March 26, 2012

SCHEDULE "C" – FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Antrim Energy Inc. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements.[1] This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 using forecast prices and costs and constant 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.

"Stephen E. Greer"
Stephen E. Greer, Chief Executive Officer

"Terry Lederhouse"
Terry Lederhouse, Vice President, Commercial

"Jim Perry"
Jim Perry, Director

"Colin Maclean"
Colin Maclean, Director

March 26, 2012

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[1] **Appendix 1 to Companion Policy 51-101CP sets out the meanings of certain terms that are used in sections 1 and 2 of this Report or in NI 51-101 or the Companion Policy.**

SCHEDULE "D"

ANTRIM ENERGY INC.

Audit Committee Charter
(February 23, 2011)

Purpose

1. The Audit Committee will assist the Board in meeting its responsibilities and will provide oversight concerning:

   1.1 the preparation and disclosure of the consolidated financial statements, Management's Discussion and Analysis and annual and interim earnings press releases prior to release of the Company;

   1.2 the credibility, integrity objectivity and adequacy of review procedures of financial reporting and public disclosure of financial information;

   1.3 the Independent Auditor's qualifications, independence and performance;

   1.4 the compliance by the Company with legal and regulatory reporting requirements.

2. The Committee will also prepare any report required by the rules of the Commission to be included in any proxy statement prepared by the Company or in the annual directors' report to shareholders.

Membership and Meetings

Membership

1. The Committee will be comprised of no fewer than three members as appointed by the Board of Directors all of which, in the opinion of the Board, are unrelated Directors.

2. Each Committee member will meet the independence, financial literacy and other membership requirements of the Toronto Stock Exchange and the rules and regulations of the AIM market of the London Stock Exchange and such other securities regulatory authorities having jurisdiction over the Company (the "Commissions").

3. At least one member of the Committee will have recent relevant experience of audit and financial matters.

Meetings

1. The Committee will meet in person or telephonically as often as it deems necessary, but not less frequently than four times per year.

2. Meetings of the Committee should be attended by representatives of the Company's principal external auditors ("Independent Auditors"), the Chief Financial Officer, Legal Counsel and others as deemed appropriate by the Committee.

3. The Committee will meet with management in connection with the consideration and approval of the Company's interim unaudited consolidated financial statements and annual audited consolidated financial statements. The Independent Auditors will be engaged by the Company to conduct a business review of

each of the Company's interim unaudited consolidated financial statements. In connection with the Company's interim unaudited and annual audited consolidated financial statements, the Committee will meet privately with the Independent Auditor. In addition, the Committee may also meet privately from time to time with such other persons or groups as the Committee deems appropriate.

4. The Committee Chair will be responsible for calling the meetings of the Committee, establishing meeting agenda with input from management, supervising the conduct of the meetings and providing the Board with a timetable of significant financial statement milestones.

5. A majority of the number of appointed Committee members will constitute a quorum for conducting business at a meeting of the Committee.

Committee Authority and Responsibilities

Relationship with the Independent Auditors

1. The Committee will make recommendations to the Board with respect to the appointment or replacement of the Independent Auditor. In accordance with applicable laws, shareholders will be asked to ratify and approve the appointment of the Independent Auditor.

2. The Committee will approve and update the Board with regards to compensation and oversight of the work of the Independent Auditor for the purpose of preparing or issuing an audit report or related work.

3. The Independent Auditor will report directly to the Committee.

Pre-approval of Audit and Non-Audit Services

1. The Committee has the authority to pre-approve all auditing services and permitted non-audit services to be performed by the Independent Auditor for the Company and its subsidiaries.

Resources of the Committee

1. The Committee has the authority to retain independent legal, accounting or other advisors.

2. The Company will provide for funding, as and when deemed necessary or advisable by the Committee, for payment of compensation to the Independent Auditor and to any advisors employed by the Committee. Where the estimated fees for such services are in excess of $50,000, the unanimous consent of all Committee members is required prior to the engagement of such services.

3. Upon the request of the Committee, the Company will provide to each Committee member an induction and appropriate training for the role of an audit committee member.

Reports to the Board

1. The Committee will make available to the Board all Committee recommendations and Committee meeting minutes.

Charter Reviews

1. The Committee will review and reassess the adequacy of this Charter annually and recommend any proposed changes to the Board for approval.

Performance Assessment

1. The Corporate Governance Committee or the Committee will annually review the Audit Committee's own performance.

Whistle-blowing and Complaint Procedures

1. The Committee will oversee the Company's whistle-blowing policy as developed and approved by the Board.

2. The Committee will establish procedures for:

    2.1 The receipt, retention and treatment of complaints received by the company regarding accounting, internal accounting controls, or auditing matters;

    2.2 The confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

Financial Statement and Disclosure Matters

The Committee will:

1. Review and discuss with the Board, and the Independent Auditor as deemed necessary:

    1.1 The annual audited and quarterly unaudited consolidated financial statements of the Company, earnings press releases and disclosures made in Management's Discussion.

    1.2 Significant financial reporting issues, judgments, accruals, reserves or other estimates made in connection with the preparation of the Company's consolidated financial statements, including any significant changes in the Company's selection or application of accounting principles, any major issues relating to the adequacy of the Company's internal controls and any special steps adopted in light of material control deficiencies.

    1.3 The accounting treatment of unusual or non-recurring transactions.

    1.4 The effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements.

2. Review and discuss with the Board reports from the Independent Auditors on:

    2.1 All critical accounting policies and practices to be used.

    2.2 All material alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, the ramifications of each alternative and the treatment preferred by the Independent Auditor.

    2.3 Other material written communications between the Independent Auditor and management, such as any management letter or schedule of unadjusted differences.

3. Receive and review reports, and discuss with the Board, on the Company's disclosure controls and procedures and the adequacy of internal controls over financial reporting and public disclosure of financial information to provide reasonable assurance that they are sufficient to meet the requirements under National Instrument 52-109.

4. Discuss with management and the Board the Company's earnings press releases (including any use of "pro-forma" or "adjusted non-GAAP information"), financial information and earnings guidance provided to analysts and rating agencies.

5. Discuss with management and the Board the Company's major financial risk exposures and the policies and procedures management has taken to monitor and control such exposures.

6. Discuss with the Independent Auditor the conduct of the audit, including any difficulties encountered in the course of the audit, any restrictions on the scope of activities or access to requested information, and any disagreements with management.

Oversight of the Company's Relationship with the Independent Auditor

The Committee will:

1. At least annually, review a report from the Independent Auditor describing:

    1.1 the Independent Auditor's internal quality-control procedures;

    1.2 any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm;

    1.3 any steps taken to deal with any such issues, and

    1.4 all relationships between the Independent Auditor and the Company.

2. Evaluate the qualifications, performance and independence of the Independent Auditor and the lead audit partner.

3. Consider whether the auditor's quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining the auditor's independence and produce an annual report explaining how these controls provide adequate protection of auditor independence.

4. Ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law. Consider whether, in order to assure continuing auditor independence, it is appropriate to adopt a policy of rotating the independent auditing firm on a regular basis.

5. Review and approve hiring policies related to current and former staff of the present and former Independent Auditor.

6. Meet with the Independent Auditor prior to the audit to discuss the planning and staffing of the audit.

Limitation of Audit Committee's Role

1. While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company's consolidated financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the Independent Auditor.

Annual General Meeting of Shareholders

1. The Committee Chair will be present at the annual general meeting of shareholders of the Company to answer any questions relating to the audit function.

Public Disclosure

1. This Charter will be disclosed in the Company's Annual Information Form, included on the Company's web-site and will be made available upon request sent to the Company's Corporate Secretary. The Company's annual report to shareholders will state that this Charter is available on the Company's web-site and will be available upon request to the Company's Corporate Secretary.