IVANHOE ENERGY INC
Form 10-K
March 17, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013
Commission file number: 000-30586

Ivanhoe Energy Inc.
(Exact name of registrant as specified in its charter)

Yukon, Canada (State or other jurisdiction of incorporation or organization)	98-0372413 (IRS Employer Identification No.)

654-999 Canada Place
Vancouver, BC, Canada V6C 3E1
(604) 688-8323
(Address and telephone number of the registrant's principal executive offices)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, No Par Value	Toronto Stock Exchange The NASDAQ Capital Market

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. o Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. o Yes þ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T

(§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). o Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o	Accelerated filer	þ
Non-accelerated filer	o	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes þ No

As of June 30, 2013, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $82,643,930 based on the Toronto Stock Exchange closing price on that date. At March 7, 2014, the registrant had 114,824,253 common shares outstanding.

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ABBREVIATIONS

As generally used in the oil and gas industry and in this Annual Report on Form 10-K ("Annual Report"), the following terms have the following meanings:

bbl	=	barrel	mbbls/d	=	thousand barrels per day
bbls/d	=	barrels per day	mboe	=	thousands of barrels of oil equivalent
boe	=	barrel of oil equivalent	mboe/d	=	thousands of barrels of oil equivalent per day
boe/d	=	barrels of oil equivalent per day	mmbbls	=	million barrels
mbbls	=	thousand barrels	mmbbls/d	=	million barrels per day

Oil equivalents compare quantities of oil with quantities of gas or express these different commodities in a common unit. A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6 mcf/1 bbl). Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to “dollars” or to “$” are to US dollars and all references to “Cdn$” are to Canadian dollars. The noon-day exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	2013	2012	2011
Closing	0.94	1.01	0.98
High	1.02	1.03	1.06
Low	0.93	0.96	0.94
Average noon	0.97	1.00	1.01

On March 7, 2014, the noon-day exchange rate was US$0.92 for Cdn$1.00.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

With the exception of historical information, certain matters discussed in this Annual Report, including those appearing in Items 1 and 2 – Business and Properties and Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), are forward-looking statements that involve risks and uncertainties.

Statements that contain words such as "could", "should", "can", "anticipate", "estimate", "propose", "plan", "expect", "see "will", "may" and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking statements" within the meaning of the "safe harbor" provisions of the United States Private Securities Litigation Reform Act of 1995. In particular, forward-looking statements contained in this Annual Report include, but are not limited to statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil prices; future production levels; future royalty and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future asset acquisitions or dispositions; future sources of funding for the Company's capital programs; future debt levels; availability of future credit facilities; possible commerciality of the Company's projects; development plans or capacity expansions; future ability to execute dispositions of assets or businesses; future formation of joint ventures and other business relationships with third parties; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long term assets; ultimate recoverability of reserves or resources; expected operating costs; estimates on a per share basis; future foreign currency exchange rates, future expenditures and future allowances relating to environmental matters and the Company's ability to comply therewith; dates by which certain areas will be developed, come on-stream or reach expected operating capacity; and changes in any of the foregoing may be forward-looking statements.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

The forward-looking statements contained in this Annual Report are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. By their nature, forward-looking statements involve inherent risks and uncertainties, including the risk that the outcome that they predict will not be achieved. Undue reliance should not be placed on forward-looking statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in the forward-looking statements, including those set out below and those detailed in Item 1A, "Risk Factors," and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," in this Annual Report. Such factors include, but are not limited to: the Company's short history of limited revenue, losses and negative cash flow from its current exploration and development activities in Canada, Ecuador, Mongolia and the United States; the Company's limited cash resources and consequent need for additional financing; the ability to raise capital as and when required, or to raise capital on acceptable terms; the timing and extent of changes in prices for oil and gas; competition for oil and gas exploration properties from larger, better financed oil and gas companies; environmental risks; title matters; drilling and operating risks; uncertainties about the estimates of reserves and the potential success of the Company's Heavy-to-light ("HTL®") technology; the potential success of the Company's oil and gas properties in Canada, Ecuador and Mongolia; the prices of goods and services; the availability of drilling rigs and other support services; legislative and government regulations; political and economic factors in countries in which the Company operates; and implementation of the Company's capital investment program.

The forward-looking statements contained in this Annual Report are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement.

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PART I

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Ivanhoe Energy Inc. (“Ivanhoe,” the “Company,” “we,” “our,” or “us”) is an independent international heavy oil developm company focused on pursuing long term growth in its reserve base and production using advanced technologies, including its HTL® technology. Core operations are in Canada and Ecuador, with business development opportunities worldwide.

The Company was incorporated pursuant to the laws of the Yukon Territory of Canada, on February 21, 1995, under the name 888 China Holdings Limited. On June 3, 1996, the Company changed its name to Black Sea Energy Ltd. On June 24, 1999, Black Sea Energy Ltd. merged with Sunwing Energy Ltd. (“Sunwing”), and the name was changed to Ivanhoe Energy Inc.

In 2005, Ivanhoe completed a merger with Ensyn Group Inc. (“Ensyn”) acquiring the proprietary, patented heavy oil upgrading process called HTL®. In July 2008, the Company acquired from Talisman Energy Canada (“Talisman”) oil sand interests, including certain oil sand leases in the Athabasca region of Canada (“Tamarack” or the “Tamarack Project”). Later in 2008, the Company signed a contract with the Ecuador state oil companies to explore and develop Ecuador’s Pungarayacu heavy oil field in Block 20. In 2009, Ivanhoe sold its wholly owned subsidiary, Ivanhoe Energy (USA) Inc., disposing of its oil and gas exploration and production operations in the United States (“US”). Also in 2009, the Company acquired a production sharing contract for the Nyalga Block XVI in Mongolia, through the takeover of PanAsian Petroleum Inc., a privately-owned corporation. In 2012, the Company sold its wholly owned subsidiary, Pan-China Resources Ltd, and assigned 100% of its participating interest in the Contract for Exploration, Development and Production in the Zitong Block, in both cases to third parties, disposing of its oil and gas exploration and production operations in China.

CORPORATE STRATEGY

Ivanhoe continues to pursue its core strategies, which are:

— Seek out heavy oil development projects globally that have operational needs that can benefit from our proprietary HTL® technology;

— Bias new country entry and business development to projects that, because of their remote setting, geo-political status or operational needs, have been overlooked by the broader industry, subsequently expanding efforts in the new locations to more conventional oil and gas industry activities; and

— Maximize the value of existing assets through strategic investment, development and partnerships.

Importance of the Heavy Oil Segment of the Oil and Gas Industry

The global oil and gas industry is being impacted by the declining availability of low cost replacement reserves. This has resulted in marked shifts in the demand and supply landscape. Ivanhoe believes that, despite the recent emergence of light shale oils, the long term supply and demand for oil globally will require the development of higher cost and lower value resources, including heavy oil.

Heavy oil developments can be segregated into two types: conventional heavy oil that flows to the surface without thermal enhancement and non-conventional heavy oil and bitumen. While the Company focuses on the non-conventional heavy oil, both types of oil play an important role in our corporate strategy.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most other oil basins, including the Middle East and the Far East. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world heavy oil production has become increasingly more common.

Key advances in technology for non-conventional heavy oil and bitumen, including improved remote sensing, horizontal drilling and new thermal techniques have led to sustained increases in project activity.

These newer technologies have generated increased interest in heavy oil resources. Nevertheless, remaining challenges for profitable exploitation include: i) the requirement for steam and electricity to help extract heavy oil; ii) the need for diluent to move the oil once it is at the surface; iii) the heavy versus light oil price differentials; and iv) conventional upgrading technologies are limited to very large scale, high capital cost facilities. These challenges can lead to “distressed” assets, where economics are poor, or to “stranded” assets, where the resource cannot be economically produced.

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Ivanhoe's Value Proposition

With the application of the HTL® process, Ivanhoe seeks to address the key heavy oil development challenges and do so at a relatively small minimum economic scale.

Ivanhoe's HTL® technology is a partial upgrading process that is designed to operate economically in facilities as small as 10,000 to 30,000 bbls/d. This is substantially smaller than the minimum economic scale for conventional stand-alone upgraders such as delayed cokers, which typically operate at scales of over 100,000 bbls/d. The HTL® process is an analogue of the fluid catalytic cracking process, a tried and tested concept in oil processing. The key advantage of HTL® is the short cracking residence time of a few seconds. This results in smaller, less costly facilities and eliminates the need for hydrogen in hydrotreating units, an expensive, large minimum scale step typically required in conventional upgrading. HTL® has the added advantage of converting the by-products from the upgrading process into onsite energy, rather than generating large volumes of low value coke.

The HTL® process offers significant advantages as a field located upgrading alternative, integrated with the upstream heavy oil production operation. HTL® provides four key benefits to the producer:

— virtual elimination of external energy requirements for steam generation and/or power for upstream operations;

— elimination of the need for diluent or blend oils for transport;

— capture of the majority of the heavy versus light oil value differential; and

— relatively small minimum economic scale of operations suited for field upgrading and for smaller field developments.

Project economics can be enhanced with the addition of HTL®. HTL®'s value proposition is greatest the more isolated the resource and where the resource owner has the fewest monetization alternatives.

Implementation Strategy

Ivanhoe is an oil and gas company with a patented technology which addresses several major problems confronting the oil and gas industry today. In addition, with Ivanhoe's experience in thermal recovery schemes, the Company is in a position to add value and leverage its technology advantage by working with partners on stranded heavy oil resources around the world.

The Company's continuing strategy is as follows:

— Advance its two key heavy oil projects in Canada and Ecuador. Continue to deploy personnel and financial resources in support of the Company's goal to become a significant heavy oil producer.

— Advance the HTL® process. Additional development work will continue to advance the HTL® process through the commercial application of HTL® upgrading in Canada, Ecuador and beyond.

— Enhance the Company's financial position to support its major projects. Implementation of large projects requires significant capital outlays. The Company is working on various financing initiatives and establishing the relationships required for future development activities.

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Build internal capabilities. The Company continues to seek to build its internal leadership and technical capabilities by maintaining key personnel associated with each major project and additional critical technical capabilities as needed.

— Continue to deploy the personnel and the financial resources to capture additional opportunities for development projects utilizing the Company's HTL® process. Commercialization of the Company's upgrading process requires close alignment with partners, suppliers, host governments and financiers.

PROPERTY DESCRIPTIONS

Our core oil and gas operations are located in two geographic areas: Canada and Ecuador. The Technology Development operation captures costs incurred to develop, enhance and identify improvements in the application of the HTL® technology. The Company also has an exploration project in Mongolia. Net income, capital expenditures and identifiable assets for these segments appear in Note 18 to the consolidated financial statements in Item 8 and in the MD&A in Item 7 of this Annual Report.

Canada

Tamarack, acquired from Talisman in 2008, is a 6,880 acre lease located approximately 10 miles northeast of Fort McMurray, Alberta, Canada. The Tamarack Project envisages a two-phased 40,000 bbl/d steam-assisted gravity drainage

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thermal recovery (“SAGD”) and HTL® facility. Our independent reserve evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), has assigned net probable reserves after royalties of 136 mmbbls of bitumen to Tamarack.

Ivanhoe filed an Environmental Impact Assessment for the Tamarack Project in November 2010. Regulators completed their initial review of the Company’s application and, as is customary, provided an initial set of Supplemental Information Requests (“SIRs”) in the third quarter of 2011. The Company submitted the supplemental information to the regulators in the fourth quarter of 2011.

The Company received additional SIRs in the second and fourth quarters of 2012 and responded to the SIRs in July and November 2012, respectively. On January 21, 2013, the Company received a Completeness Determination from Alberta Environment and Sustainable Resource Development pursuant to Section 53 of the Environmental Protection Act following its review of the Tamarack Environmental Impact Assessment. In August 2013, the Company enhanced its application by submitting an addendum. The addendum included results acquired in the first quarter of 2013 from the testing and coring of three additional wells and 3D seismic data from a portion of the project's area.

In December 2013, the Company learned that the Alberta Energy Regulator (“AER”) intends to conduct a thorough technical review of the factors that affect reservoir containment of shallow SAGD projects and will be consulting with stakeholders to develop formal regulatory requirements. Following discussions with each affected industry applicant, the AER issued a bulletin with interim guidelines. The AER now indicates that they will develop the new requirements following extensive industry and stakeholder engagement. This decision and process affects all shallow SAGD projects, including Ivanhoe's Tamarack Project.

Ivanhoe met with the AER in December 2013 and was advised that, per the interim guidelines, the Tamarack application would not continue to be processed until (a) 3D seismic has been collected and interpreted over the entire initial development area and (b) the maximum operating pressure meets the interim guidelines.

The Company then prepared to launch a seismic program over the remaining portion of the initial development area for which seismic had not been shot, and continued to discuss with the AER the validity of the Company’s methodology for its proposed maximum operating pressure. The Company was given an indication that the AER might consider assessing and ruling on the validity of its methodology, but in a letter dated February 6, 2014 and received by the Company on February 24, 2014, the AER said that it would not do so. At that point the Company cancelled the costly seismic program for this winter.

The Company is continuing its discussions with the AER and is exploring its alternatives for moving the Tamarack Project forward. In addition, the Company continues its discussions with local stakeholders to address any statements of concern as part of the regulatory process. Ivanhoe continues to believe that its proposed development plan for Tamarack is safe and economically viable and expects the project will be approved. However, until the new formal regulatory requirements are known, Ivanhoe cannot determine whether the Tamarack Project, as currently proposed, will ultimately fit within those requirements.

The Company has suspended activity, including capital investment, on its current Tamarack oil sands project application, except for essential items, pending clarity from the AER on the final regulatory requirements for shallow SAGD projects and/or any continuing discussions the Company might have with the AER.

Ecuador

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a 30 year specific services contract with the Ecuadorian state oil companies Petroecuador and Petroproduccion. The contract (which was subsequently assigned to another Ecuadorian state oil company, Petroamazonas) gives Ivanhoe the right to explore and develop the Pungarayacu heavy oil field in Block 20, an area of 426 square miles, approximately 125 miles southeast of Quito, Ecuador's capital city. The specific services contract provides for the Ecuadorian Government to pay a fee for each barrel of oil produced from the field. This fee fluctuates based on three published producer price indices and, in the Company's opinion, tracks West Texas Intermediate benchmark oil price movements. The Company anticipates using HTL® technology, as well as providing advanced oilfield technology, expertise and capital to develop, produce and upgrade heavy oil from the Pungarayacu field. The Company may also explore for lighter oil in the contract area and blend any light oil discoveries with the heavy oil for delivery to Petroamazonas.

In 2010, Ivanhoe drilled its first two appraisal wells in the Pungarayacu field. The second, IP-5b, well was successfully drilled, cored and logged to a total depth of 1,080 feet. The well was perforated in the Hollin oil sands and steam was successfully injected into the reservoir resulting in production of heated heavy oil. In 2011, the heavy crude oil extracted from the IP-5b well was successfully upgraded to local pipeline specifications using Ivanhoe's proprietary HTL® upgrading process at its test facility in San Antonio. Later in 2011, the Company completed a 190-kilometre 2-D seismic survey over the southern portion of Block 20. Following the analysis of the seismic program, Ivanhoe began preparing to drill one exploration well into the deeper Hollin and pre-cretaceous horizons in the southern part of the Pungarayacu Block to test the potential of lighter oil resources, which would prove beneficial for blending purposes and overall project economics.

In 2012, the Company drilled well IP-17 in the pre-cretaceous zone in the Southern portion of the Block to test the formations in this area. It was successfully drilled to a depth of 13,594 feet, where it was cased and suspended. The well confirmed the presence of hydrocarbons in the Hollin and Napo formations and evaluated the potential of the deeper, pre-cretaceous structures. While hydrocarbons were found in the Hollin and Napo formations, the reservoir in the immediate vicinity of the well was not suitable for commercial exploitation.

During 2013, the Company drilled well IP-14b to a total depth of 1,150 feet and encountered hydrocarbons in the Hollin formation. On December 31, 2013, the first phase of the Specific Services Contract between Ivanhoe and the Ecuadorian Government, representing the evaluation phase, ended. The next steps in the contract would be the pilot and exploitation phases. However during 2013, the Company has been engaged in discussions with a large international oil company regarding the concept of jointly investing and participating in the development and operation of Block 20. During the course of these discussions, the parties have developed a framework of commercial terms which has been used in separate discussions with the Government of Ecuador. The ultimate objective of these discussions with the Ecuadorian Government has been the establishment of mutually acceptable terms and conditions allowing for the formation of a consortium between the Company and the third party to jointly develop Block 20. The formation of the consortium is contingent upon the successful negotiation of definitive and legally binding agreements that reflect the achievement of this objective. Although Ivanhoe remains optimistic, there is no assurance that this objective will be achieved or achieved in a timely manner. The outcome of these discussions is likely to have a significant impact on the Company's continuing participation in the Block 20 project.

Asia

Mongolia

Through a merger with PanAsian Petroleum Inc. in November 2009, we acquired a production sharing contract ("PSC") for the Nyalga Block XVI in the Khenti, Govi Sumber and Tov provinces in Mongolia. The project is operated by a Mongolian registered company Shaman LLC ("Shaman") which is an indirect wholly-owned subsidiary of Panasian Energy Ltd. The block currently covers an area of approximately 9,239 square kilometers. The five year exploration period is divided into three consecutive phases, consisting of two years ("Phase I"), one year ("Phase II") and two years ("Phase III"), with the ability to elect a two year extension following Phase I or Phase II.

During the initial seismic program, approximately 16% of the block in the Delgerkhaan area was declared by the Mongolian government to be a historical site and operations in this area were suspended. A letter from the Mineral Resources and Petroleum Authority of Mongolia ("MRPAM") stated that the obligations under year one of Phase I would be extended for one year from the time the Company is allowed to re-enter the suspended area. To date, access has not been granted and discussions with MRPAM are ongoing. As a result, the government adjusted the dates on which the project year begins. Phase II is now considered to have commenced on July 20, 2010.

From late 2009 through the first quarter of 2010, the Company acquired an additional 465 kilometres of 2-D seismic across Block XVI, for a total of 925 kilometres of 2-D seismic data over the Kherulen sub-basin. The seismic was used to drill two wells in 2011. The first exploration well, N16-1E-1A, was drilled and abandoned as the well did not encounter oil shows in the reservoir. The Company observed oil staining, fluorescence and increases in background gas at its second exploration well site at N16-2E-B. After extensive laboratory testing of the drill cuttings from the second well it was determined that the oil was not of a mobile nature and the decision was made to forego any completion operations. Well site reclamation work has been completed and the local government has signed off on the acceptance of the reclamation works.

In early 2013, the Company completed the acquisition of a 106 kilometer 2-D seismic program and completed processing of the results. This new seismic data has been incorporated with the recent drilling results by independent consultants and an up-to-date prospects report has been finalized as of the third quarter of 2013. The report has recommended potential for three drill sites to be evaluated based on this review result.

The five year initial term of the exploration license was to expire July 19, 2013. The Company applied for, and was granted a two year extension to the PSC after meeting the minimum expenditure requirement, extending the term to July 19, 2015 providing additional time to find a partner or buyer.

The PSC permits an additional two year extension from July 2015.

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RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the information provided below, please refer to the "Supplementary Disclosures About Oil and Gas Production Activities (Unaudited)" set forth in Item 8 in this Annual Report for certain details regarding the Company's oil and gas proved reserves, the estimation process and production by country. We have not filed with nor included in reports to any other US federal authority or agency, any estimates of total proved oil reserves since the beginning of the last fiscal year.

The following table presents estimated probable and possible oil reserves as of December 31, 2013.

Summary of Oil and Gas Reserves Using Average 2013 Prices

(mbbl)	Canada Bitumen Tamarack
Probable	
Developed	–
Undeveloped	141,477
Possible	
Developed	–
Undeveloped	31,465

Canada

Probable and Possible Reserves

No additional reserves were assigned to Tamarack in 2013 as further reserve development is subject to regulatory approval of the Company's application for the project, sanctioning by the Board of Directors and further delineation drilling.

Possible reserves are within the Tamarack Project application area, but have a lower degree of certainty compared to our probable reserves due to lower quality reservoir characteristics or decreased certainty based on the level of reservoir delineation. See Internal Control over Reserve Estimation for a distinction between possible reserves and probable reserves.

Basis of Reserves Estimates

Recovery estimates for Tamarack are based on a combination of reservoir simulation, detailed reservoir characterization and analogue project performance.

Internal Control over Reserve Estimation

Management is responsible for the estimates of oil and gas reserves and for preparing related disclosures. Estimates and related disclosures in this Annual Report are prepared in accordance with U.S. Securities and Exchange Commission ("SEC") requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to reflect SEC requirements. As a Canadian public company, we are also subject to the disclosure requirements of National Instrument 51-101 (''NI 51-101'') of the Canadian Securities Administrators ("CSA"), which requires us to disclose reserves and other oil and gas information in accordance with the prescribed standards of NI 51-101. The prescribed standards differ, in certain respects, from SEC requirements. See the Special Note to Canadian Investors on page 10.

The process of estimating reserves requires complex judgments and decision making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including, but not limited to:

— expected reservoir characteristics based on geological, geophysical and engineering assessments;

— future production rates based on historical performance and expected future operating and investment activities;

— future oil and gas prices and quality differentials;

— assumed effects of regulation by governmental agencies; and

— future development and operating costs.

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We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, these estimates may change substantially as additional data from government regulations, ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Reserve estimates are categorized by the level of confidence that they will be economically recoverable. Proved reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the technologies used in the estimation process have been demonstrated to yield results with consistency and repeatability.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. Although possible reserve locations are found by “stepping out” from proved reserve locations, estimates of probable and possible reserves are, by their nature, more speculative than estimates of proved reserves and, accordingly, are subject to substantially greater risk of being realized.

Our reserve estimates were prepared by GLJ and reviewed by our in-house Senior Engineering Advisor (“SEA”). Our SEA is a professional engineer (P.Eng.) in Alberta, with over 23 years of broad industry experience with the past 14 years focusing on petroleum engineering in the oil and gas industry in Canada. His past experience includes development, planning and managing subsurface engineering for oil projects in Canada, forecasting and optimizing production, and evaluating new recovery processes.

All reserve information in this Annual Report is based on estimates prepared by GLJ. The technical personnel responsible for preparing the reserve estimates at GLJ meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas by the Society of Petroleum Engineers. GLJ is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Our Board of Directors reviews the current reserve estimates and related disclosures as presented by the independent qualified reserves evaluators in their reserve report. Our Board of Directors has approved the reserve estimates and related disclosures.

Special Note to Canadian Investors

Ivanhoe is an SEC registrant and files annual reports on Form 10-K; accordingly, our reserves estimates and regulatory securities disclosures are prepared based on SEC disclosure requirements. In 2003, the CSA adopted NI 51-101 which prescribes standards that Canadian public companies engaged in oil and gas activities are required to follow in the preparation and disclosure of reserves and related information.

Until 2010, we had an exemption from certain requirements of NI 51-101 which permitted us to substitute disclosures based on SEC requirements for some of the annual disclosure required by NI 51-101 and to prepare our reserve estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers and the standards of the COGE Handbook, modified to reflect SEC requirements. This exemption is no longer available to us for reserve reporting in Canada.

We have, however, received another exemption from the CSA which, among other things, allows us to disclose reserves and related information in accordance with applicable US disclosure requirements provided that we also make disclosure of our reserves and other oil and gas information in accordance with applicable NI 51-101 requirements. We disclose reserve information in accordance with applicable US disclosure requirements in this Annual Report. We disclose reserves and other oil and gas information in accordance with applicable NI 51-101 requirements in our Form 51-101F1, Statement of Reserves Data and Other Oil and Gas Information, which is filed with the CSA and available at www.sedar.com.

The reserve quantities disclosed in this Annual Report represent reserves calculated on an average, first-day-of-the-month price during the 12 month period preceding the end of the year for 2013, using the standards contained in SEC Regulations S-X and S-K and Accounting Standards Codification 932 Extractive Activities – Oil and Gas (section 235), formerly Statement of Financial Accounting Standards No. 69, “Disclosures About Oil and Gas Producing Activities”. Such

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information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the current SEC requirements and the NI 51-101 requirements are as follows:

— SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US, whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;

— the SEC mandates disclosure of proved reserves calculated using an average, first-day-of-the-month price during the 12 month period preceding and existing costs only, whereas NI 51-101 requires disclosure of reserves and related future net revenues using forecasted prices, with additional constant pricing disclosure being optional; and

— the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors, whereas NI 51-101 requires issuers to engage such evaluators.

The foregoing is a general and non-exhaustive description of the principal differences between SEC disclosure requirements and NI 51-101 requirements. Please note that the differences between SEC and NI 51-101 requirements may be material.

Production, Sales Prices and Production Costs

	2013	2012(1)	2011
Oil production (bbls/d)	–	850	967
Average sales price ($/bbl)	–	114.28	105.93
Average operating cost (2) ($/bbl)	–	42.90	44.10

(1) 2012 production information relates to the Company's project in Dagang which was sold in December 2012 and includes eleven months of results.
(2) Average operating costs per unit of production, based on net interest after royalties, represent lifting costs, including a windfall gain levy. According to the "Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business," enterprises exploiting and selling oil in China are subject to a windfall gain levy (the "Windfall Levy") if the monthly weighted average price of oil exceeds a certain threshold. Average operating costs exclude depletion and depreciation, income taxes, interest, selling and general administrative expenses.

Ivanhoe's oil production originated in Asia, specifically the Dagang and Daqing fields in China. The majority of our production came from Dagang and was sold to the Chinese national petroleum company. In December 2012, the Company sold the productive oil wells that were associated with its properties in China. No oil production occurred in 2013 as a result of the sale of all producing assets in 2012.

Acreage

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Asia – Mongolia	–	–	2,283,234	2,283,324
Canada	–	–	7,520	7,520
Latin America	–	–	272,639	272,639

(1) Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of oil and gas regardless of whether or not such acreage

contains proved reserves.

The Tamarack lease in Canada will expire in October 2016, but Ivanhoe has sufficient drill density to be granted a continuation by the Alberta Department of Energy one year prior to expiry or upon first production, whichever comes first. Ivanhoe filed the Tamarack Project application in 2010 and the application has been under regulatory review since that time. Recent regulatory changes will require Ivanhoe to submit additional technical data and information in order for process of the application to continue. In addition, there are pending regulatory changes which have yet to be finalized which could materially affect the project as current envisaged

We signed a specific services contract with the Ecuadorian state oil companies in October 2008 that allows us to develop and operate Block 20 for a term of 30 years, extendable by mutual agreement of the parties, for two additional periods of five years each, depending on the interests of the Ecuadorian Government and in conformity with local laws. On December 31, 2013, the first phase of the Specific Services Contract between Ivanhoe and the Ecuadorian Government, representing the evaluation phase, ended. The next steps in the contract would be the pilot and exploitation phases. However, as discussed above, during 2013, Ivanhoe and a large international oil company were engaged in discussions to create a consortium to jointly develop Block 20 beginning in 2014. Ivanhoe is also engaged in separate discussions with the Ecuadorian Government respecting the consortium proposal. The outcome of these discussions is likely to have a significant impact on the Company’s continuing participation in the Block 20 project.

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Acreage in Mongolia is subject to periodic relinquishments up to the end of the exploration period and the remaining acreage, if any, designated for appraisal and development will expire 20 years after the final commercial discovery on the Nyalga block.

Drilling Activity

(net wells)(1)	Net Exploratory Productive	Net Exploratory Dry Holes	Net Exploratory Total	Net Development Productive	Net Development Dry Holes	Net Development Total	Total Wells Drilled
Asia							
2013(2)	–	–	–	–	–	–	–
2012(2)	–	1.0	1.0	1.0	–	1.0	2.0
2011	–	1.0	1.0	2.5	–	2.5	3.5

(1) Net wells are the sum of fractional working interests owned in gross wells.
(2) At December 31, 2012 and December 31, 2013 we were not actively drilling wells.

TECHNOLOGY DEVELOPMENT

The Company’s Technology Development segment captures HTL® activities. In April 2005, Ivanhoe merged with Ensyn and thereby obtained an exclusive, irrevocable license to the HTL® process for all applications other than biomass. The Company has since continued to expand patent coverage to protect innovations to the HTL® technology and to significantly extend Ivanhoe’s portfolio of HTL® intellectual property. Ivanhoe is the assignee of six granted US patents and currently has 13 US patent applications pending. In other countries, the Company has 57 patents granted and 32 pending patents. In addition, Ivanhoe owns exclusive, irrevocable licenses to 17 global patents for the rapid thermal processing process as it pertains to petroleum. The expiration date for Ivanhoe’s key patents is 2032.

Global demand for crude oil and liquid fuels is expected to continue to create an opportunity for additional exploitation of heavy oil resources. Many heavy oil resources exist in the form of stranded assets which tend to be geographically remote or difficult to access. In these remote locations, industrial infrastructure may be immature and the availability of construction resources is constrained. In addition, production techniques continue to become ever more complex. As a result, the development of heavy oil remains economically challenged and deployment of conventional solutions to solve these challenges can be impractical. However, because of the global abundance of heavy oil deposits, we believe heavy oil is expected to remain an important global hydrocarbon resource. An economic means of extraction is therefore needed to address the challenges of heavy oil development.

Ivanhoe Energy’s HTL® process is intended to provide an alternative to the traditional approach to the transportation of heavy crude oil. HTL® aims to convert heavy, viscous crude oil into lighter, stable, more valuable and easily transportable products. The essence of the process undertakes rapid thermal conversion of heavy oil into high value Synthetic Crude Oil (“SCO”).

HTL® should position the heavy oil producer to capture the majority of the market value differential between heavy and light oil and eliminate the need for adding diluent to enable transportation. In addition, by-products from HTL® can be used to produce significant amounts of energy for utilization on-site. Traditionally, heavy crude is diluted with light oil such that it can be transported from the well to the refinery. HTL® offers a new process where partial upgrading can be deployed close to the well, resulting in a much lighter, lower viscosity and stable product that can be transported to the refinery without diluent.

HTL® plants can be economically constructed at smaller scales than conventional upgrading processes and operate at a fraction of the per-barrel cost. Reduced complexity as well as a smaller footprint make it possible for HTL® plants to operate in remote locations not possible with conventional technologies. By integrating HTL® onto an FPUSO (Floating, Production, Upgrading, Storage, and Offloading) vessel, it becomes possible to develop stranded offshore heavy oil fields.

Ivanhoe has modularized the HTL® design, further widening the gap between the cost of HTL® and that of conventional upgrading facilities. The modules are fabricated off-site and transported via barge, rail or road to the construction site.

When processing heavy crude oils with an 8° to 16° API gravity, HTL® produces a synthetic crude oil of 16° to 24° API. The process substantially reduces the viscosity and converts the residual oil to high value synthetic crude oil, which can be processed by most modern refineries. The HTL® synthetic crude oil, when priced at the refinery gate and blended with a typical crude diet, has been valued by a third party engineering firm at close to Brent pricing.

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The Kline Group, consultants to the energy and chemical industries, completed an evaluation in 2013 which compares HTL® to more than 10 other upgrading technologies under development today. In this comparison, The Kline Group concluded that HTL® is the leading partial upgrading technology based on five significant advantages:

- it is a novel carbon rejection process that is best suited for application in the field;
- it produces high yields of valuable, transportable SCO;
- it is in an advanced stage of developmet;
- it requires lower capital costs; and,
- it requires lower operating costs.

The company intends to commercialize the technology through two different models. The field integrated model, such as the Tamarack Project, integrates an HTL® facility with production. Ivanhoe is also developing midstream projects in which resource owners deliver heavy crude to a centralized HTL® facility that would partially upgrade the heavy oil for a fee. See Part I, Item 1A "Risk Factors - We may not successfully commercialize our HTL® technology.

Ivanhoe has a feedstock test facility ("FTF") located at the Southwest Research Institute in San Antonio, Texas. The FTF has the functionality of a full-scale commercial facility, but at a size that allows for multi-run optimization and testing of third party crude oils from around the world. It provides an accurate estimate of the commercial processing characteristics of target crudes and facilitates the generation of intellectual property, including the development of new patents and operational know-how. In 2010, the FTF supported basic and front-end engineering for a commercial-scale HTL® plant for the Tamarack Project in Canada. In 2011, activities at the FTF focused on the assay and analyses related to the successful upgrading of the heavy oil recovered from the Pungarayacu IP-5b well in Ecuador. In 2012, Ivanhoe continued to exploit the unit to further technology development, process improvement as well as commercial engineering of HTL® plants. In 2013, Ivanhoe processed heavy crude for Ecopetrol in the FTF and produced commercially attractive yields and product properties.

CERTAIN FACTORS AFFECTING THE BUSINESS

Competition

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for and development of new sources of supply, is particularly competitive. Our competitors include major, intermediate and junior oil and gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to more easily absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business, adversely affecting our competitive position. Our competitors may be able to pay more for producing oil and gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies, and consummate transactions in a highly competitive environment. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers.

Environmental Regulations

Our oil and gas and HTL® operations are subject to various levels of government regulation relating to the protection of the environment in the countries in which we operate. We believe that our operations comply in all material respects with applicable environmental laws.

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. As well, environmental laws regulate the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. We anticipate that changes in environmental legislation may require, among other things, increased air quality standards for our operations and may result in increased capital expenditures.

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Operations in Canada are governed by comprehensive federal, provincial and municipal regulations. We submitted the Regulatory Application/Environmental Impact Assessment for the Tamarack Project to the Government of Alberta in November 2010. The AER is a new regulatory authority responsible for our project application. In January 2014, the AER announced that it is reviewing its standards for approving all shallow SAGD projects, including ours. While the process for establishing the new standards continues, the processing of our application has been suspended. Part of the approval process will require the disposition of two Statements of Concerns, one filed by Suncor Energy Inc. and another by the Athabasca Chipewyan First Nation. The Company will be required to obtain numerous ancillary approvals prior to commencing operations and will be subject to ongoing environmental monitoring and auditing requirements.

Ecuador and Mongolia continue to develop and implement more stringent environmental protection regulations and standards for industry. Projects are currently monitored by governments based on the approved standards specified in the environmental impact statements prepared for individual projects, located on the Company's website.

Government Regulations

Our business is subject to certain federal, state, provincial and local laws and regulations in the regions in which we operate relating to the exploration for, and development, production and marketing of, crude oil and gas, as well as environmental and safety matters. In addition, the Ecuadorian and Mongolian governments regulate various aspects of foreign company operations in their respective countries. Such laws and regulations have generally become, globally, more stringent in recent years, often imposing greater liability on a larger number of potentially responsible parties. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

As at December 31, 2013, we had 75 employees. None of our employees are unionized.

AVAILABLE INFORMATION

The principal corporate office of Ivanhoe Energy Inc. is located at 999 Canada Place, Suite 654, Vancouver, British Columbia, V6C 3E1. Our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9 and our operational headquarters are located at 101-6th Avenue SW, 19th Floor, Calgary, Alberta, T2P 3P4.

Electronic copies of the Company's filings with the United States Securities and Exchange Commission (the "SEC") and the Canadian Securities Administrators (the "CSA") are available, free of charge, through our website (www.ivanhoeenergy.com) or, upon request, by contacting our investor relations department at (403) 817-1108. The information on our website is not, and shall not be, deemed to be part of this Annual Report.

Each of the SEC (www.sec.gov) and the CSA (www.sedar.com) maintains a website from which you can access our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the CSA. A copy of this Annual Report is located at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

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ITEM 1A: RISK FACTORS

We are exposed to various risks, some of which are common to other companies in the oil and gas industry and some of which are unique to our business. Certain risks set out below constitute "forward-looking statements" and readers should refer to the "Special Note Regarding Forward-Looking Statements" on page 4.

If we are unable to adequately fund our substantial capital and operating requirements our ability to continue as a going concern could be adversely affected

Our business is capital intensive and the advancement of our projects in Canada, Ecuador and Mongolia and our HTL® technology commercialization initiatives require significant funding. We have a history of operating losses and our current exploration and development activities do not generate cash flow sufficient to meet our funding obligations and capital expenditure plans. Historically, we have relied upon equity capital as our principal source of funding. The sustainability of our business is dependent upon our having reliable access to additional capital in order to meet obligations associated with our existing projects and capitalize upon potentially valuable opportunities to acquire and develop future projects. We may seek financing from a combination of strategic investors and/or public and private debt and equity markets, either at the parent company level or at a project level. There is no assurance that we will be able to obtain such financing or obtain it on favorable terms and any future equity issuances may be dilutive to our existing shareholders.

Our access to financing may be limited by an inability to attract strategic partners willing to invest in our projects on acceptable terms, ongoing volatility in equity and debt markets and a sustained downturn in the market price of our common shares. Without access to sufficient amounts of financing or the ability to undertake other cash generating activities, we may have to delay or forego potentially valuable project acquisition and development opportunities or default on existing funding commitments to third parties. This could result in the dilution or forfeiture of our rights in existing projects, which would cast substantial doubt that the Company would be able to continue as a going concern.

Talisman's security interest in our Tamarack Project assets could impede our ability to secure third party debt

When we acquired our Tamarack Project in 2008, we incurred a series of debt obligations in favor of Talisman secured by a first fixed charge and security interest in the Tamarack oil sands leases and a general security interest in all of our present and after acquired property, other than our equity interests in our subsidiaries (through which we hold our HTL® technology and our projects in Ecuador and Mongolia). Although we have satisfied substantially all of the material debt obligations we owed to Talisman, we remain subject to a contingent payment obligation of up to Cdn$15.0 million, which is also secured by Talisman's security interest. This contingent obligation becomes due and payable if and when we obtain the requisite government and other approvals necessary to develop the northern border of one of the leases. We are obliged to use commercially reasonable efforts to obtain these approvals. However, despite our efforts, the risks inherent in oil field development, including potential environmental considerations, create significant uncertainty as to when, if ever, we will be able to obtain these approvals and, consequently, we cannot predict when, if ever, this contingent obligation will become due and payable or when Talisman's security interest will be released and discharged.

The Talisman security interest restricts our ability to grant security over our Tamarack Project assets to secure debt obligations to third parties that we may create in the future. Assets unencumbered by the Talisman security interest may be insufficient as collateral to secure these obligations. This could adversely affect our ability to obtain debt financing or to obtain it on favorable terms. Since Talisman's security interest secures a contingent obligation of potentially indefinite duration, we cannot predict when, and on what terms, we will be able to mitigate this risk.

The volatility of oil prices may affect the commercial viability of our projects

The commercial viability of our exploration and development projects is highly dependent on the price of oil. Prices also affect our ability to borrow money or raise additional capital. Even relatively modest changes in oil prices may significantly change an oil and gas company's revenues, results of operations, cash flows and proved reserves. Historically, the market for oil has been volatile and is likely to continue to be volatile in the future.

Oil prices may fluctuate widely in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as weather conditions; overall global economic conditions; terrorist attacks or military conflicts; political and economic conditions in oil producing countries; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; the level of demand and the price and availability of alternative fuels; speculation in the commodity futures markets; technological advances affecting energy consumption; governmental regulations and approvals; and proximity and capacity of oil pipelines and other transportation facilities. These factors and the volatility of the energy markets make it extremely difficult to predict future oil price movements with any certainty.

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We may be required to take write-downs if oil prices decline, our estimated development costs increase or our exploration results deteriorate

We may be required to write-down the carrying value of our properties if oil prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. See "Critical Accounting Principles and Estimates – Impairment" in Item 7, MD&A, of this Annual Report.

Estimates of reserves and future net revenue may change if the assumptions on which such estimates are based prove to be inaccurate

Reserve estimates are based on many assumptions that may turn out to be inaccurate. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment, the assumptions used regarding prices for oil and gas, production volumes, required levels of operating and capital expenditures and quantities of recoverable oil reserves. Any significant variance from the assumptions used could result in the actual quantity of reserves and future net cash flow being materially different from those estimated. In addition, actual results of drilling, testing and production and changes in oil and gas prices after the date of the estimate may result in revisions to reserve estimates. Revisions to prior estimates may be material.

We may incur significant costs on exploration or development which may prove unsuccessful or unprofitable

There can be no assurance that the costs we incur on exploration or development will result in an acceptable level of economic return. We may misinterpret geological or engineering data, which may result in material losses from unsuccessful exploration or development drilling efforts. We bear the risks of project delays and cost overruns due to unexpected geologic conditions; equipment failures; equipment delivery delays; accidents; adverse weather; government and joint venture partner approval delays; construction or start-up delays; and other associated risks. Such risks may delay expected production and/or increase production costs.

We compete for oil and gas properties and personnel with many other exploration and development companies throughout the world who have access to greater resources

We operate in a highly competitive environment and compete with oil and gas companies and other individual producers and operators, many of which have longer operating histories and substantially greater financial and other resources. Many of these companies not only explore for and produce oil and gas, but also carry on refining operations and market petroleum and other products on a worldwide basis. We also compete with companies in other industries supplying energy, fuel and other commodities to consumers. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business and more readily endure longer periods of reduced oil and gas prices. Our competitors may be able to pay more for productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects.

We compete with other companies to recruit and retain the limited number of individuals who possess the requisite skills and experience that are relevant to our business. This competition exposes us to the risk that we will have to pay increased compensation to such employees or increase the Company's reliance on, and associated costs from partnering or outsourcing arrangements. There can be no assurance that employees with the abilities and expertise we require will be available.

Changes to laws, regulations and government policies in the jurisdictions in which we operate could adversely affect our ability to develop our projects

Our projects in Canada, Ecuador and Mongolia are subject to various international, federal, state, provincial, territorial and local laws and regulations relating to the exploration for and the development, production, upgrading, marketing, pricing, taxation and transportation of heavy oil, bitumen and related products and other matters, including environmental protection.

The exercise of discretion by governmental authorities under existing legislation and regulations, the amendment of existing legislation and regulations or the implementation of new legislation or regulations, affecting the oil and gas industry could materially increase the cost of developing and operating our projects and could have a material adverse impact on our business. For example, AER's recent announcement that it is reviewing its standards for approving all shallow SAGD projects is likely to result in delays in the process of developing our Tamarack Project. There can be no assurance that laws, regulations and government policies relevant to our projects will not be changed in a manner which may adversely affect our ability to develop and operate them. In the case of our Tamarack Project, until AER's new regulatory requirements are known, we cannot determine whether the Tamarack Project, as currently proposed, will ultimately meet those requirements. If it does not, there can be no assurance that the project can be developed and operated in a manner that is both economically viable and compliant with regulatory requirements. Failure to obtain all necessary permits, leases, licenses and approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of our projects and increase costs, all of which could have a material adverse effect on our business.

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Construction, operation and decommissioning of these projects will be conditional upon the receipt of necessary permits, leases, licenses and other approvals from applicable government and regulatory authorities. The approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. An inability to secure local and regional community support could result in the necessary approvals being delayed or denied. There is no assurance that such approvals will be issued or, if granted, will not be appealed or cancelled or that they will be renewed upon expiry or will not contain terms and conditions that adversely affect the final design or economics of our projects.

Complying with environmental and other government regulations could be costly and could negatively impact our operations

Our operations are governed by various international, federal, state, provincial, territorial and local laws and regulations. Oil, gas, oil sands and heavy oil extraction, upgrading and transportation operations are subject to extensive regulation. Various approvals are required before such activities may be undertaken. We are subject to laws and regulations that govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. These laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities in protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater; and require remedial measures be taken with respect to property designated as contaminated.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations may result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations.

No assurance can be given with respect to the impact of future environmental laws or the approvals, processes or other requirements mandated by such laws on our ability to develop or operate our projects in a manner consistent with our current expectations. No assurance can be given that environmental laws will not limit project development or materially increase the cost of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

Our business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks

Our operations are subject to many risks inherent in the oil and gas industry. In the course of carrying out our operations, we may encounter unexpected and materially adverse circumstances or events, including fires, natural disasters, catastrophic weather conditions, explosions, unusual or unexpected geological formations including formations with abnormal pressures, blowouts, cratering, equipment malfunctions, pipeline ruptures, spills or discharges of hazardous substances, or title problems. Any such unexpected and materially adverse circumstances or events could cause us to experience material losses.

We are insured against some, but not all, of the hazards associated with our business, so we may sustain losses that could be substantial if we experience events or circumstances for which we are not insured or are underinsured. The occurrence of an uninsured or underinsured event could have a material adverse impact on our financial condition and results of operations. We do not carry business interruption insurance and, therefore, we bear the risk of any loss or deferral of revenues resulting from a curtailment of future production.

Under environmental laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability for environmental damage is available at a reasonable cost. Accordingly, we could be exposed to potentially significant losses and liabilities if environmental damage occurs.

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SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive and may be unsustainable

We intend to integrate established SAGD thermal recovery techniques with our patented HTL® upgrading process. Heavy oil recovery using the SAGD process is subject to technical and financial uncertainty. Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels for the production of steam used in the recovery process. The amount of steam required in the production process can vary and any material variance can impact costs. The performance of the reservoir can also affect the timing and levels of production using SAGD technology. Although SAGD technology is now being used by several producers, commercial application of the technology is still in its early stages relative to other methods of production. In the absence of an extended and demonstrated operating history, there can be no assurances with respect to the sustainability of SAGD operations. The AER is reviewing its approval standards for SAGD project applications and the outcome is uncertain.

We may not successfully commercialize our HTL® technology

Successful commercialization of our HTL® technology in the oil and gas industry is contingent upon our ability to identify and acquire appropriate sources of feedstock for, and economically design, construct and operate, commercial-scale plants and a variety of other factors, many of which are outside our control. To date, commercial-scale HTL® plants have only been constructed and operated in the bio-mass industry.

Technological advances could render our HTL® technology obsolete

We expect that technological advances in competing processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to be made. It is possible that these competing processes and procedures could cause our HTL® technology to become uncompetitive or obsolete.

Alternate sources of energy could lower the demand for the products that our HTL® technology is intended to produce

Alternative sources of energy are continually under development. If reliance upon petroleum based fuels decreases, the demand for products that our HTL® technology is intended to produce may decline. It is possible that technological advances in engine design and performance could reduce the use of petroleum based fuels, which would also lower the demand for products that our HTL® technology is intended to produce.

Efforts to commercialize our HTL® technology may give rise to claims of infringement upon the patents or other proprietary rights of others

We might not become aware of claims of infringement of the patents or other rights of others in deploying the HTL® technology until after we have made a substantial investment in the development and commercialization of HTL® projects. Third parties may claim that our HTL® designs and operations infringe their patents. Legal actions could be brought against us claiming damages and seeking injunctions that would prevent us from testing or commercializing our technology. If an infringement action were successful, in addition to potential liability for damages, we could be required to obtain and pay for a claiming party’s license or be enjoined from using the HTL® technology. We might have to expend substantial resources in litigation defending any such infringement claims. Some possible claimants may have significantly more resources to spend on litigation than we do.

A breach of confidentiality obligations could put us at competitive risk and potentially damage our business

While discussing potential business relationships with third parties, we may disclose confidential information respecting operating results or proprietary intellectual property. Although we regularly require third parties to sign confidentiality agreements prior to the disclosure of any confidential information, an unauthorized disclosure of confidential information could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Certain projects are at a very early stage of development

Our projects are at varying stages of development. We are in the midst of a regulatory approval process with the Government of Alberta in respect of our Tamarack Project. The approval of our Tamarack Project has been suspended pending review by the AER of standards for approval of all shallow SAGD projects. Although we believe that we will successfully complete the regulatory approval process, there is no assurance that the process will be successfully completed, or completed on a timely basis. If the regulatory approval process becomes more protracted than anticipated, construction of the Tamarack

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Project could be significantly delayed. There is also a risk that the Government of Alberta may not approve the project as proposed or that it may impose conditions upon its approval which could significantly impair the economics of the project. Our projects in Ecuador and Mongolia are at a very early stage of development; no reserves have yet been established and no detailed feasibility or engineering studies have yet been produced.

There can be no assurances that any of our projects will be completed within any anticipated time frame or within the parameters of any anticipated capital cost. We have yet to establish a definitive schedule for financing and fully developing these projects. Other factors, in addition to lack of financing, may hinder our ability to develop and operate our projects on a timely basis. These include breakdowns or failures of equipment or processes; construction performance falling below expected levels of output or efficiency; design errors; challenges to proprietary technology; contractor or operator errors; non-performance by third party contractors; labor disputes; disruptions or declines in productivity; increases in materials or labor costs; inability to attract sufficient numbers of qualified workers; delays in obtaining, or conditions imposed upon, regulatory approvals; violation of permit requirements; disruption in the supply of energy; and catastrophic events such as fires, earthquakes, storms or explosions.

Our Tamarack Project may be exposed to title risks and aboriginal claims

We hold our interest in the Tamarack Project through leases granted by the Government of Alberta, which we purchased from Talisman. There is a risk that the land covered by these leases may be subject to prior unregistered agreements or interests or undetected claims or interests that could impair our leasehold title. Any such impairment could adversely affect our ability to construct and operate the Tamarack Project on the basis presently contemplated, which could have a material adverse effect on our financial condition, results of operations and ability to execute our current business plan in a timely manner.

Aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where oil and gas operations are conducted, including claims that, if successful, could delay or otherwise adversely affect the construction and operation of the Tamarack Project, which could have a material adverse effect on our business.

Our Block 20 Project in Ecuador may be at risk if the agreement through which we hold our interest is challenged or cannot be enforced

We hold our interest in the Block 20 Project in Ecuador through a specific services agreement with an Ecuadorian national oil company. The agreement is governed by the laws of Ecuador. Although the agreement has been translated into English, the official and governing language of the agreement is Spanish and, if any discrepancy exists between the official Spanish version of the agreement and the English translation, the official Spanish version prevails. There may be ambiguities, inconsistencies and anomalies between the official Spanish version of the agreement and the English translation that could materially affect how our rights and obligations under the agreement are conclusively interpreted and such interpretations may be materially adverse to our interests.

The dispute resolution provisions of the Block 20 agreement stipulate that disputes involving industrial property, including intellectual property, and technical or economic issues are subject to international arbitration. Other disputes are subject to resolution through mediation or arbitration in Ecuador. There is a risk that we will be unable to agree with the Ecuadorian national oil company as to whether a dispute should be referred to international arbitration or mediation or arbitration in Ecuador. There can also be no assurance that the Ecuadorian national oil company will comply with the dispute resolution provisions or otherwise voluntarily submit to arbitration.

Government policy in Ecuador may change to discourage foreign investment, or legal requirements pertinent to foreign investment in Ecuador may change in unforeseen ways. There can be no assurance that our investments and assets in Ecuador will not be subject to nationalization, requisition or confiscation, whether legitimate or not, by any authority or body. While the Block 20 agreement contains provisions for compensation and reimbursement of losses we may suffer under such circumstances, there is no assurance that such provisions would effectively restore the value of our original investment. There can be no assurance that Ecuadorian laws protecting foreign investments will not be amended or abolished or that the existing laws will be enforced or interpreted to provide adequate protection against any or all of the risks described above. There can also be no assurance that the Block 20 agreement will prove to be enforceable or provide adequate protection against any or all of the risks described above.

We have been engaged in discussion with a large international oil company regarding jointly investing and participating in the development and operation of Block 20. During the course of these discussions, the parties have developed a framework of commercial terms which has been used in separate discussions with the Government of Ecuador. The ultimate objective of discussions with the Government of Ecuador has been the establishment of mutually acceptable terms and conditions allowing for the formation of a consortium between the Company and the third party to jointly develop Block 20. The

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formation of the consortium is contingent upon the successful negotiation of definitive and legally binding agreements that reflect the achievement of this objective. There is no assurance that this objective can be achieved or achieved in a timely manner. The outcome of these discussions is likely to have a significant impact on the Company's continuing participation in the Block 20 project.

Our business may be harmed if we are unable to retain our interests in licenses, leases and contracts

The interests we hold in our projects are derived from licenses, leases and contracts. If we fail to meet the specific requirements of the instrument through which we hold our interest in a particular project, it may terminate or expire. We may not be able to meet any or all of the obligations required to maintain our interest in each such license, lease or contract. Some of our project interests will terminate unless we fulfill such obligations. If we are unable to satisfy these obligations on a timely basis, we may lose our rights in these projects. The termination of our interests in these projects may harm our business.

Our principal shareholder may significantly influence our business

As at the date of this Annual Report, Robert M. Friedland, a director and our Executive Co-Chairman, was our largest shareholder, owning approximately 17% of our common shares. As a result, he has the voting power to significantly influence our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all, or substantially all, of our assets. In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common shares.

If we lose our key management and technical personnel, our business may suffer

We rely upon a relatively small group of key management personnel. In respect of the technological aspect of our business, we also rely heavily upon our scientific and technical personnel. Our ability to implement our business strategy may be constrained and the timing of implementation may be impacted if we are unable to attract and retain sufficient personnel. We do not maintain any key man insurance. Although we have employment agreements with each of our key management and technical personnel, there is no assurance that these individuals will remain in our employ in the future. An unexpected partial or total loss of their services would harm our business.

Information regarding our future plans reflects our current intent and is subject to change

We describe our current exploration and development plans in this Annual Report. Whether we ultimately implement our plans will depend on a number of factors including the availability and cost of capital; our ability to demonstrate the commerciality of the HTL® technology; favorable exploration results; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment; supplies; personnel; timeliness of regulatory and third party approvals; reliability of project development cost estimates; and our ability to attract other industry partners to participate with us in our projects in order to reduce costs and exposure to risks.

We assess and gather data about our projects on an ongoing basis and it is possible that additional information will cause us to alter our schedule for the development of a particular project or determine that the project should not be pursued at all or that it should be disposed of. This information may also cause us to acquire or initiate new projects. Our plans regarding our projects might change.

We may be unable to maintain the listing of our common shares on NASDAQ despite the reverse stock-split

In September, 2013, the Company received a notification from the Listing Qualification Department of the NASDAQ notifying the Company that the Company did not meet the minimum bid price requirements set forth in the NASDAQ Listing Rules and that the Company could regain compliance if at any time prior to March 5, 2014 the closing bid price of the Company's common shares was at least $1.00 for a minimum of 10 consecutive business days. On February 18, 2014, the Company applied to the NASDAQ for an additional compliance period of 180 days, which was granted. If the Company does not otherwise regain compliance with the minimum bid price requirements in a timely manner, the Company may need to take other action, including seeking the approval of its shareholders to effect a reverse split of its common shares to maintain its NASDAQ listing, as it did in 2013 in order to remedy a previous minimum bid price deficiency, or seeking inclusion in a different U.S. marketplace or trading system.

Reducing the number of issued and outstanding common shares through a reverse split is intended to increase the per share market price of the common shares and thereby cure the minimum bid price deficiency. However, the per share market price of the common shares will also be affected by the Company's financial and operational results, its financial position, including its liquidity and capital resources, the development of its projects, industry conditions, the market's

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perception of the Company's business and other factors, which are unrelated to the number of common shares outstanding. There is a risk that, despite a reverse split or any other action taken by the Company, the common shares will be delisted from the NASDAQ.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

Businesses have become increasingly dependent on digital technologies to conduct day-to-day operations. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial of service on websites.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and upgrading activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, for compliance reporting, and for upgrading process data modelling. The use of mobile communication devices has also increased rapidly. The complexity of the technologies needed to extract oil in increasingly remote physical environments without adequate infrastructure and global competition for oil and gas resources make certain information more attractive to thieves.

We depend on digital technology, including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil reserves, and for many other activities related to our business. Our business partners, including vendors, service providers, and financial institutions, are also dependent on digital technology.

Our technologies, systems and networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

— unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our competitive position in developing our oil resources;

— data corruption, communication interruption, or other operational disruption during drilling activities could result in a dry hole cost or even drilling incidents;

— data corruption or operational disruption of production infrastructure could result in loss of production or accidental discharge;

— a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt one of our major projects, effectively delaying the start of cash flows from the project;

— a cyber-attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

— a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues and increased expenses;

— a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and

— significant business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Although to date we have not experienced any material losses relating to cyber incidents, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

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ITEM 3: LEGAL PROCEEDINGS

Cotundo Minerales S.A.

On August 9, 2013, Cotundo Minerales S.A. ("Cotundo") served us with a notice of claim against the Company, two of its subsidiaries, and Company board member Robert Friedland, filed in the Supreme Court of British Columbia. The Company and its two subsidiaries have been served; to the Company's knowledge Robert Friedland has not been served. The Company and its two subsidiaries filed a response on September 24, 2013. The suit alleges that the Company misused confidential information provided to it by Cotundo related to the Pungarayacu heavy oil field in Ecuador. Cotundo seeks damages in the form of lost profits, an imposition of a trust in favor of Cotundo, a transfer of Ivanhoe's interest in the Pungarayacu field to Cotundo, interest, and costs.

The plaintiff and claims in the recent lawsuit by Cotundo overlap with those from a previous lawsuit filed against the Company, its subsidiaries, Mr. Friedland and others in the United States District Court for the District of Colorado on November 20, 2008. That case was dismissed by the trial court for lack of personal jurisdiction, and that dismissal was affirmed by the United States Court of Appeals for the Tenth Circuit on July 12, 2012. The plaintiffs filed a writ of certiorari with the United States Supreme Court, which was denied on January 14, 2013. Both the district court and the appellate court in the prior case awarded fees and costs to the Ivanhoe defendants.

The likelihood of loss or gain resulting from this dispute, and the estimated amount of ultimate loss or gain, are not determinable or reasonably estimable at this time. The Company believes that the plaintiff's claims have no merit.

GAR Energy

On December 30, 2010, the Company received a demand for arbitration from GAR Energy and Associates, Inc. ("GAR Energy") and Gonzalo A. Ruiz and Janis S. Ruiz as successors in interest to, and assignees of, GAR Energy. GAR Energy subsequently abandoned its demand for arbitration and filed suit against the Company and subsidiaries in the Superior Court for Kern County, California on March 11, 2011. The lawsuit alleges breach of contract, fraud and other misconduct arising from a consulting agreement and various other agreements between GAR Energy and the Company relating to the Pungarayacu heavy oil field. The plaintiffs seek actual damages of $250,000 and a portion of the Company's interest in the Pungarayacu field. The plaintiffs seek other miscellaneous relief, including requests for a declaration of some of the parties' rights and legal relations under a consulting agreement, attorneys' fees and certain litigation costs and expenses, disgorgement of the Company's past, current and/or future profits attributable to the Pungarayacu field and certain other fields in Ecuador, tort damages and exemplary and punitive damages, the imposition of constructive trusts over certain amounts and profits requested by the plaintiffs, and pre-judgment and post-judgment interest. The Company removed the case to the United States District Court for the Eastern District of California and all of the defendants have answered and filed counterclaims for attorneys' fees. Defendants filed a motion to dismiss certain claims and to compel arbitration of others. Plaintiffs' filed a motion to remand the case to state court. On December 23, 2011, the Magistrate Judge denied plaintiffs' motion to remand and issued findings and recommendations that would send all of the parties and all of the claims to arbitration should the district court Judge assigned to the case adopt them. On January 19, 2012 the district court Judge adopted the Magistrate Judge's findings and recommendations in full, ordered the parties to arbitration and stayed the district court proceedings to allow for the completion of the arbitration.

The arbitration evidentiary hearing on the merits (trial) was held September 9-13, 2013. On March 14, 2014 the Company received the verdict from the arbitrators. The panel awarded a take-nothing judgment against the plaintiffs and in favor of the Company, meaning that the Company prevailed entirely on the merits. The Company will now consider taking action to recover its attorneys' fees in defending the case.

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ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common shares trade on the Toronto Stock Exchange (the "TSX") and The NASDAQ Capital Market ("NASDAQ") under the symbols "IE" and "IVAN" respectively. The trading range of our common shares is as follows:

		TSX (Cdn$)		NASDAQ (US$)	
		High	Low	High	Low
2013	Q1	2.85	1.80	2.09	1.77
	Q2	1.61	0.92	1.98	0.90
	Q3	1.10	0.63	1.07	0.60
	Q4	0.95	0.37	0.93	0.35
2012(1)	Q1	4.02	2.46	3.99	2.49
	Q2	3.45	1.32	3.45	1.77
	Q3	2.28	1.50	2.31	1.56
	Q4	2.67	1.23	2.74	1.23
2011(1)	Q1	10.74	8.01	11.01	8.25
	Q2	8.52	4.74	8.91	4.80
	Q3	5.88	3.06	6.09	2.96
	Q4	4.41	2.25	4.38	2.16

(1) Prior periods have been restated to reflect the three for one common share consolidation which occurred on April 25, 2013 described below.

On December 31, 2013, the closing price of our common shares was Cdn$0.64 on the TSX and $0.62 on NASDAQ.

As at March 7, 2013, a total of 114,824,253 of our common shares were issued and outstanding and held by 318 holders of record with an estimated 23,800 additional shareholders whose common shares were held for them in street name or nominee accounts.

On April 22, 2013, the Company's shareholders approved a proposal to affect a reverse stock-split of the Company's common shares in order to regain compliance with the minimum bid price requirements set forth in the NASDAQ Listing Rules. The reverse stock-split took effect on April 25, 2013. As a result of the reverse stock-split shareholders received one new common share for every three old common shares held and an initial trading price for the new common shares above the NASDAQ minimum bid price was established thereby enabling the Company to regain compliance on May 9, 2013.

On September 6, 2013, the Company received a notification letter from the Listing Qualifications Department of the NASDAQ notifying the Company that the Company again did not meet the minimum bid price requirements set forth in the NASDAQ Listing Rules and that the Company could regain compliance if at any time prior to March 5, 2014 the closing bid price of the Company's common shares was at least $1.00 for a minimum of 10 consecutive business days. For additional information, refer to the Form 8-K filed on September 12, 2013. On February 18, 2014, the

Company applied to the NASDAQ for an additional compliance period of 180 days, which was granted and will expire on September 2, 2014.

DIVIDENDS

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the Yukon Business Corporations Act, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or after payment of the dividend would be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

EXEMPTIONS FROM CERTAIN NASDAQ MARKETPLACE RULES

As a Canadian issuer listed on NASDAQ, we are not required to comply with certain of NASDAQ's Marketplace Rules and instead may comply with applicable Canadian requirements. As a foreign private issuer, we are only required to comply with the following NASDAQ rules: (i) we must have audit and compensation committees that satisfy applicable NASDAQ requirements and that are composed of directors each of whom satisfy NASDAQ's prescribed independence standards; (ii) we must provide NASDAQ with prompt notification after an executive officer of the Company becomes aware of any material non-compliance by us with any applicable NASDAQ Marketplace Rule; (iii) our common shares must be eligible for a Direct Registration Program operated by a clearing agency registered under Section 17A of the Exchange Act; and (iv) we must provide a brief description of any significant differences between our corporate governance practices and those followed by US companies quoted on NASDAQ.

Applicable Canadian rules pertaining to corporate governance require us to disclose in our management proxy circular, on an annual basis, our corporate governance practices, including whether or not our independent directors hold regularly scheduled meetings at which only independent directors are present, but there is no legal requirement in Canada for independent directors to hold regularly scheduled meetings at which only independent directors are present.

Although our independent directors hold meetings from time to time, as and when considered necessary or desirable by the independent lead director or by any other independent director, such meetings are not regularly scheduled. Our non-management directors hold regularly scheduled meetings but not all of our non-management directors are independent.

ENFORCEABILITY OF CIVIL LIABILITIES

We are a company incorporated under the laws of Yukon, Canada. Some of our directors, controlling shareholders, officers and representatives of the experts named in this Annual Report reside outside the US and a substantial portion of their assets and our assets are located outside the US. As a result, it may be difficult to effect service of process within the US upon the directors, controlling shareholders, officers and representatives of experts who are not residents of the US or to enforce against them judgments obtained in the courts of the US based upon the civil liability provisions of the federal securities laws or other laws of the US. There is doubt as to the enforceability in Canada, against us or against any of our directors, controlling shareholders, officers or experts who are not residents of the US, in original actions or in actions for enforcement of judgments of US courts, of liabilities based solely upon civil liability provisions of the US federal securities laws. Therefore, it may not be possible to enforce those actions against us, our directors, officers, controlling shareholders or experts named in this Annual Report.

EXCHANGE CONTROLS AND TAXATION

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon Territory, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the Investment Canada Act (the "Investment Act"), which generally prohibits a reviewable investment by an investor that is not a "Canadian", as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a "WTO investor" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value of our assets, as determined under Investment Act regulations, was Cdn$5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value (a "Cultural Business"). Currently, an investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2014 is Cdn$354 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer through the ownership of common shares. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

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The Canadian Federal Government has announced certain forthcoming amendments (the "Amendments") to the Investment Act. Once they come into force, the Amendments would generally raise the thresholds that trigger governmental review. Specifically, with respect to WTO investors, the Amendments would see the thresholds for the review of direct acquisitions of control of a business which is not a Cultural Business increase from the current Cdn$354 million (based on book value) to Cdn$600 million (to be based on the "enterprise value" of the Canadian business) for the two years after the Amendments come into force, to Cdn$800 million in the following two years and then to Cdn$1 billion for the next two years. Thereafter, the threshold is to be adjusted to account for inflation. The Amendments will come into force when the government enacts regulations which, among other things, will provide how the "enterprise value" is to be determined.

The Investment Act also provides that the Minister of Industry may initiate a review of any acquisition by a non-Canadian of our common shares or assets if the Minister considers that the acquisition "could be injurious to (Canada's) national security".

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to shareholders as dividends in respect of the common shares held at a time when the beneficial owner is not a resident of Canada within the meaning of the Income Tax Act (Canada), will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-US Income Tax Convention (1980), as amended, (the "Convention"). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a US resident that is entitled to the benefits of the Convention is generally 15%. However, if the beneficial owner of such dividends is a US resident corporation that is entitled to the benefits of the Convention and owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax-exempt entities, which are residents of the US for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

See table under "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" set forth in Item 12 in this Annual Report.

PERFORMANCE GRAPH

See table under "Executive Compensation" set forth in Item 11 in this Annual Report.

SALES OF UNREGISTERED SECURITIES

All securities we issued during the years ended December 31, 2013, 2012 and 2011, which were not registered under the Act, have been detailed in previously filed Form 10-Qs or Form 8-Ks.

ITEM 6: SELECTED FINANCIAL DATA

SUMMARY OF SELECTED FINANCIAL DATA

The following table presents selected financial data based on International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and should be read in conjunction with our accompanying "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Item 7 of this report and with the audited consolidated financial statements and the related notes thereto included in Item 8 of this report. Results of operations are shown for continuing operations, which exclude the operations discontinued in China, for the fiscal years presented.

($000s, except per share amounts)	2013	2012	2011	2010
Results of Operations				
Net loss from continuing operations	(143,754)	(64,018)	(26,761)	(22,258)
Net loss from continuing operations per share – basic and diluted(1)	(1.25)	(0.56)	(0.23)	(0.21)
Financial Position				
Total assets	232,173	402,057	413,710	394,418
Long term debt	63,012	65,214	61,892	–
Long term derivative instruments	–	181	1,617	–
Long term provisions	2,589	3,157	1,919	3,008

(1) Prior periods have been restated to reflect the three for one common share consolidation which occurred on April 25, 2013 described in Item 5.

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ITEM 7: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2013 (the "Financial Statements"). The Financial Statements have been prepared in accordance with and using accounting policies in full compliance with IFRS as issued by the IASB and Interpretations of the International Financial Reporting Interpretations Committee.

As a foreign private issuer in the US, Ivanhoe is permitted to file with the SEC financial statements prepared under IFRS without a reconciliation to US generally accepted accounting principles ("US GAAP"). It is possible that some of our accounting policies under IFRS could be different from US GAAP.

The date of this discussion is March 17, 2014. Unless otherwise noted, tabular amounts are in thousands of US dollars. Reserves and related measures are presented net of royalty payments to governments.

BUSINESS ENVIRONMENT

The Company's core operations are in Canada and Ecuador. Canada offers a relatively stable business environment in which to operate due to established infrastructure and political stability. However the oil and gas sector currently faces challenges including transportation of oil and gas products to international markets and the associated environmental impact of these projects. The Company believes that the long term demand for oil and gas will remain strong and that further development, particularly in the heavy oil segment, will be required in order to meet this anticipated demand.

Ecuador regulates various aspects of foreign company operations and has had periods of political instability in the past. With the 2013 election of the incumbent Ecuadorian President, the Company anticipates the government's future policy toward foreign investment in oil and gas operations will remain consistent and one in which the Company can operate.

The development of the Company's oil and gas and HTL® operations are capital intensive. In the past, the Company has used external sources of funding such as public and private equity and debt markets. The Company is impacted by industry influences including commodity prices and larger macro-economic factors that may cause investors to shift their funding priorities into, or out of, the heavy-oil sector.

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HIGHLIGHTS

($000, except as stated)	2013	2012	2011
Capital expenditures	16,927	47,444	51,060
Net cash used in operating activities	(36,432)	(27,060)	(26,245)
Net loss from continuing operations	(143,754)	(64,018)	(26,761)
Net loss per share from continuing operations – basic and diluted	(1.25)	(0.56)	(0.23)

Net loss from continuing operations in 2013 was $143.8 million, an increase of $79.8 million compared to $64.0 million in 2012. The increase in net loss from continuing operations is mainly attributable to $101.1 million in non-cash impairment charges discussed in detail below, $6.9 million higher general and administrative expenses in 2013 and $1.2 million in other net changes. The increase in net loss from continuing operations was partially offset by $11.9 million higher recovery of deferred income taxes, $7.6 million lower exploration and evaluation expenses in 2013, $3.7 million in net foreign currency gains in 2013 compared to $1.2 million in net losses in 2012, $3.0 million loss on debt repayment in 2012 that did not recur in 2013 and $2.0 million lower finance expenses in 2013. The changes in the items impacting net loss from continuing operations are discussed below.

Capital expenditures amounted to $16.9 million in 2013. In Ecuador, $8.4 million was spent on environmental work, road work and in drilling of the IP-14b appraisal well. In Canada, the Company spent $7.5 million on a seismic and drilling program that will provide further information for initial development on the Tamarack Project including determining optimal well pair locations.

RESULTS OF OPERATIONS

Impairment Charges

The Company’s 2013 results included a net loss from continuing operations of $143.8 million primarily driven by a non-cash impairment charge related to HTL® of $101.1 million, resulting in a zero carrying value for this asset. The impairment charge was offset by a net recovery of $11.6 million on the corresponding future income tax liability for the FTF and intangible assets that was derecognized as a result of the impairment charge.

At the end of 2013 the Company’s market capitalization was substantially lower than the carrying value of its assets. This relationship is an indicator of impairment which results in a detailed asset evaluation under IFRS. During that evaluation the Company examines its forecasted future cash flows, given past results, and discounts them at a discount rate determined at December 31, 2013. The Company used the modified Capital Asset Pricing Model to calculate its discount rates, which steadily rose over 2013, including a sharp increase in the fourth quarter to 26%. Two factors caused this increase in discount rate, the increasing yield to maturity on the Company’s convertible debentures and the increase in the equity size premium caused by a decreasing market capitalization.

At times, the discount rate required under IFRS may be different than the discount rate used by the Company to evaluate its projects as IFRS requires point in time measurement whereas the Company, when considering commercial feasibility and value, evaluates its projects over a period of time which can minimize the volatility in discount rates when compared to short-term measurement results. IFRS is strict in using observable market data. In the fourth quarter of 2013, the Company’s share price and yields from publicly traded debt required the Company to assign additional risk premiums above what the Company has historically been required to use. Considering these factors, and as required under IFRS, the Company used a discount rate at year end of approximately 26% to conduct its impairment analysis for HTL®. For commercial and planning purposes the Company utilizes discount rates in the range 10-15%.

The Company's projected cash flows from projects utilizing HTL® technology typically generate an internal rate of return lower than the 26% discount rate used at year end, triggering the impairment charge in the period. Under IFRS, the impairment charge can be reversed in the future once facts and circumstances relating to the charge change.

The non-cash impairment charge for HTL® was driven by the application of accounting standards and capital-cost procedures given the market information available and does not represent the Company's assessment of commercial value regarding HTL®. The Company believes that the HTL® technology holds significant commercial value and continues to pursue its business development initiatives to achieve commercialization of the HTL® technology. In 2013, these efforts included engaging a third party engineering consultant firm to compare the HTL® technology to its competitors which concluded that HTL® had the opportunity to be the leading partial upgrading technology. Additional work was completed

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which also proved that HTL® synthetic crude oil is stable and compatible with conventional transportation, pipeline & storage systems and can be processed in a refinery. As well, the Company successfully upgraded heavy oil extracted from Ecopetrol S.A.'s San Fernando T2 formation in Colombia crude from 8° API to 15° API.

Operating Costs

Operating costs in the Technology Development segment are incurred at the Company's Feedstock Test Facility ("FTF") at the Southwest Research Institute in San Antonio, Texas and mainly consist of labor and materials.

FTF operating costs in 2013 were $4.4 million, relatively unchanged from the 2012 operating costs of $4.3 million.

FTF operating costs in 2012 were $4.3 million, relatively unchanged from the 2011 operating costs of $4.6 million.

General and Administrative

General and administrative ("G&A") expenses mainly consist of staff, office and legal and other contract services costs.

The Company incurred G&A expenses of $38.1 million in 2013, an increase of $7.0 million compared to costs of $31.1 million in 2012. The increase is primarily due to $3.1 million in increased legal costs mainly related to the proceedings discussed in Part I, Item 3 "Legal Proceedings" disclosed within this Annual Report, $1.0 million one-time staff costs related to severance and retention of key employees in the Asia segment in the first quarter of 2013 and the $1.3 million excess of short-term incentive compensation over the 2012 accrual. $1.6 million other G&A expenses accounted for the remainder of the difference.

The Company incurred G&A expenses of $31.1 million in 2012, a decrease of $7.5 million compared to costs of $38.6 million in 2011. G&A expenses were lower in 2012 due to lower staff and legal and other contract services costs. Staff costs decreased $3.6 million compared to 2011 because the formalization of the Company's compensation program in 2011 resulted in the Company accruing two years of short term incentive costs for that year; 2012 also benefitted from lower share-based payment expense due to higher employee turnover in 2012. Legal and other contract services costs decreased $2.0 million from 2011 mainly due to the conclusion of a lawsuit against the Company and recovery of the Company's costs as a result of a favorable ruling in that case. G&A costs also decreased $1.9 million from 2011 mainly due to less allocated shared services activity and lower professional service fees relating to audit and financing activities.

Exploration and Evaluation

Costs of exploring for, and evaluating, oil and gas properties are initially capitalized as intangible exploration and evaluation ("E&E") assets and charged to E&E expense only if sufficient reserves cannot be established or once the costs are determined to have no future value.

E&E expense in 2013 was $15.4 million, $7.6 million lower than E&E expense of $23.0 million in 2012. In July 2013, the Government of Mongolia confirmed the extension of the Company's PSC for a two year period, expiring in July 2015. The Company believes it has exceeded minimum expenditure requirements of the first 5 year term of the PSC by a significant margin. As part of the Company's refocus of global activities, it is actively pursuing potential candidates to purchase or farm-in on the Mongolian PSC. The Company has updated the geology and exploration potential of the Mongolian PSC property based on recent drilling and 2D seismic data completed early in 2012 and has identified drillable targets. The Company expensed $4.7 million in capital costs in the third quarter of 2013 to reduce the carrying value of assets related to the Mongolian PSC to their estimated recoverable amount at that time. The Company expensed the remaining $10.7 million in capital costs in the fourth quarter of 2013 to further reduce the carrying value of assets related to the Mongolian PSC to nil as the Company does not anticipate a purchase or farm-in on the Mongolian PSC in the short term due to the current uncertainty surrounding Mongolian government regulation. The Mongolian Government is currently reviewing the various laws and regulations pertaining to the mineral and energy industry in Mongolia. For this reason, committed activity for the current year has been significantly reduced and until there is greater clarity with respect to the regulatory environment in Mongolia, it is uncertain when, or if, a potential purchase or farm-in process will be successfully concluded.

E&E expense in 2012 was $23.0 million, $20.2 million higher than E&E expense of $2.8 million in 2011. The IP-17 exploratory well in the southern part of Block 20 in Ecuador led to the discovery of non-commercial quantities of hydrocarbons and the Company expensed $19.9 million in related costs in 2012. In addition, the Company also expensed $2.9 million in capital costs in 2012 relating to the second Mongolian well drilled in 2011. Independent laboratory tests finalized in September 2012 on the drill cuttings from Mongolia indicated that there is a high probability that mobile oil in the well is limited. Other E&E costs of $0.2 million were expensed in the second quarter of 2012.

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E&E expense in 2011 was $2.8 million. Drilling costs of $2.1 million were expensed in connection with the exploration well in Mongolia that was plugged and abandoned. In addition, it was determined that $0.7 million of expenditures related to the seismic program in Ecuador would have limited future value and were therefore charged to E&E expense.

Depreciation

Depreciation expense is primarily charges for the amortization of capitalized costs of the FTF but also includes furniture and equipment depreciation.

Depreciation expense in 2013 was $1.0 million, unchanged from 2012.

Depreciation expense in 2012 was $1.0 million, unchanged from 2011.

Foreign Currency Exchange

The gain or loss on foreign currency exchange results from the revaluation of monetary assets and liabilities denominated in currencies other than the Company's functional currency, the US dollar, at each period end and from the settlement of the Company's payables denominated in foreign currencies.

The Company incurred a $3.7 million gain on foreign currency exchange in 2013 compared to a $1.2 million loss in 2012. During 2013 the Canadian dollar weakened in comparison to the US dollar, resulting in gains on the translation of the Company's Convertible Debentures, which was partially offset by losses on translation of Canadian dollar cash. By contrast, during 2012, the Canadian dollar strengthened in comparison to the US dollar, resulting in losses on the translation of the Company's Convertible Debentures, which was partially offset by gains on translation of Canadian dollar cash. Despite the Company holding more Canadian dollar cash on average in 2013 than it did in 2012, the average cash balance was less than that of the Company's Convertible Debentures. Additionally, the absolute magnitude of the Canadian dollar weakening in 2013 was significantly more than the absolute magnitude of the Canadian dollar strengthening in 2012.

The Company incurred a $1.2 million loss on foreign currency exchange in 2012 compared to a $0.5 million gain in 2011. The loss on foreign exchange in 2012 is mainly due to the revaluation of the Canadian denominated Convertible Debentures as the Canadian dollar strengthened near the end of 2012 compared to the 2011 closing exchange rate resulting in a higher translated debt in 2012.

Derivative Instruments

The gain on derivative instruments results from accounting for the changes in the fair value of derivative instruments through earnings.

As at December 31, 2013, the Company valued the convertible component of the Convertible Debentures at nil compared to $0.2 million as at December 31, 2012. The lower valuation, which resulted in an unrealized gain of $0.2 million in 2012, was a result of lower Company share prices in 2013 which the Company's uses as an input in estimating the fair value of the derivative.

As at December 31, 2012, the Company valued the convertible component of the Convertible Debentures at approximately $0.2 million compared to $1.6 million as at December 31, 2011. The lower valuation, which resulted in an unrealized gain of $1.4 million in 2012, was a result of lower Company share prices in 2012 which the Company's uses as an input in estimating the fair value of the derivative.

Finance

Finance expense consists of interest expense and the unwinding of the discount rate for decommissioning obligations.

Finance expense in 2013 was $2.3 million, a decrease of $2.0 million compared to $4.3 million in 2012. The decrease is primarily due to a reduction of $3.4 million in gross interest expense resulting from lower debt in 2013 which the Company used to fund operations while closing the 2012 asset dispositions. This was partially offset by a $1.0 million increase in net interest being expensed due to lower capital expenditures to which interest would be allocated in 2013 compared to 2012 combined with a reduction of $0.4 million to holdback proceeds from the transaction with MIE Holding Corporation (“MIE”), in which the Company disposed of its wholly-owned subsidiary, Pan-China Resources Ltd. to MIE.

Finance expense in 2012 was $4.3 million, an increase of $3.9 million compared to $0.4 million in 2011. The increase was due to higher debt in 2012 which the Company used to fund operations while closing the 2012 asset dispositions as well as

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a lower allocation of interest to capital expenditures as debt funding near the last half of 2012 was used more for ongoing operations than capital projects.

Loss on Debt Repayment

The Company classified its short term debt as a financial liability measured at amortized cost which allows for transaction costs to be amortized over the life of the debt instrument.

In December 2012, subsequent to the closing of the China asset dispositions, the Company used a portion of the proceeds to repay its short term debt earlier than the maturity date of the debt. This repayment resulted in the remaining deferred transaction costs of the debt instruments being charged through earnings at the time repayment was made. In 2012, these costs amounted to $3.0 million.

Gain on Derecognition of Long Term Provision

As part of the 2005 merger agreement with Ensyn, the Company assumed a $1.9 million contingent obligation. In the third quarter of 2011, the Company determined, based on later events and clarification of contract terms, that satisfaction of the specific contractual contingencies was unlikely and the liability was derecognized.

Provision for Income Taxes

The Company recorded a deferred tax recovery of $14.3 million in 2013 compared to a recovery of $2.4 million in 2012. The $11.9 million increase in recovery is mainly due to $11.6 million in future income tax liabilities for the HTL® assets that were derecognized as a result of the impairment charge as well as a deferred tax recovery of the impairment of the Mongolia assets resulting in a recovery of $2.7 million. This was partially offset by a reduction in deferred tax recoveries of $2.4 million mainly due to non-operating losses recorded in 2012 that did not recur in 2013.

The Company recorded a deferred tax recovery of $2.4 million in 2012 compared to a recovery of $4.4 million in 2011. The $2.0 million decrease in recovery is mainly due to a reduction in the valuation allowance in 2011 in respect of certain US operating losses that were determined to be more likely than not to be realized as well as a reduction in net operating losses from lower expenses in 2012.

Discontinued Operations

Zitong Block

On December 27, 2012, Sunwing Zitong Energy, a wholly owned subsidiary of the Company, completed the transfer of the Company’s participating interest in the Zitong Petroleum Contract to Shell China Exploration and Production Co. (“Shell”).

In exchange for Sunwing’s interest in the Zitong Petroleum Contract, the Company received total pre-tax cash proceeds of $105.0 million subject to a holdback pending the completion of regulatory audits. Initial pre-tax proceeds of approximately $96.2 million were delivered on closing. The Company received the full US$5.1 million in holdback proceeds in June 2013 and the final US$3.7 million in proceeds were released as part of the 2012 China National Petroleum Corporation's cost recovery audit in December 2013.

In early 2013 Shell assumed the obligations under the Zitong Supplementary Agreement and replaced the Company’s performance bond with its own. As a result, the collateral for that performance bond, presented as restricted cash on the Company’s balance sheet at December 31, 2012, was released on February 1, 2013.

Pan-China Resources Ltd.

On December 17, 2012 the Company completed the sale to MIE of all of the outstanding shares of its indirect, wholly owned subsidiary, Pan-China Resources Ltd.

As consideration, the Company received $45.0 million in cash, less $5.4 million in adjustments and a $4.0 million holdback. The Company received $3.6 million in holdback proceeds in July 2013.

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LIQUIDITY AND CAPITAL RESOURCES

Contractual Obligations and Commitments

The following information about our contractual obligations and other commitments summarizes certain liquidity and capital resource requirements. The information presented in the table below does not include planned, but not legally committed, capital expenditures or obligations that are discretionary and/or being performed under contracts which are cancelable with a 30 day notification period.

	Total	2014	2015	2016	2017	After 2017
Long term debt(1)	68,926	–	–	68,926	–	–
Interest on long term debt(1)	9,891	3,963	3,963	1,965	–	–
Decommissioning obligations(2)	4,091	–	–	199	–	3,892
Leases	3,033	993	826	704	352	158
Total	85,941	4,956	4,789	71,794	352	4,050

(1) Long term debt is denominated in Canadian dollars and has been translated to US dollars at an exchange rate of approximately CAD=0.9402 USD.
(2) Represents undiscounted decommissioning obligations after inflation. The discounted value of these estimated obligations ($2.4 million) is provided for in the consolidated financial statements.

Long Term Debt and Interest

As described in the Financial Statements, the Company issued Cdn$73.3 million of Convertible Debentures maturing on June 30, 2016. The Convertible Debentures bear interest at an annual rate of 5.75%, payable semi-annually on the last day of June and December of each year, which commenced on December 31, 2011.

Decommissioning Provisions

The Company is required to remedy the effect of our activities on the environment at our operating sites by dismantling and removing production facilities and remediating any damage caused. At December 31, 2013, Ivanhoe estimated the total undiscounted, inflated cost to settle its decommissioning obligations in Canada, for the FTF in the US and in Ecuador was $4.1 million. These costs are expected to be incurred in 2016-2032, 2029 and 2038, respectively.

Leases

The Company has long term leases for office space and vehicles, which expire between 2014 and 2018.

Other

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Tamarack Project leases, the Company will be required to make a cash payment to Talisman of up to Cdn$15.0 million, as a conditional, final payment for the 2008 purchase transaction.

From time to time, Ivanhoe enters into consulting agreements whereby a success fee may be payable if and when either a definitive agreement is signed or certain other contractual milestones are met. Under the agreements, the consultant may receive cash, common shares, stock options or some combination thereof. Similarly, agreements entered into by the Company may contain cancellation fees or liquidated damages provisions for early termination. These fees are not considered to be material.

The Company may provide indemnities to third parties, in the ordinary course of business, that are customary in certain commercial transactions, such as purchase and sale agreements. The terms of these indemnities will vary based upon the contract, the nature of which prevents Ivanhoe from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company's management is of the opinion that any resulting settlements relating to indemnities are not likely to be material.

In the ordinary course of business, the Company is subject to legal proceedings being brought against it. While the final outcome of these proceedings is uncertain, the Company believes that these proceedings, in the aggregate, are not reasonably likely to have a material effect on its financial position or earnings.

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Sources and Uses of Cash

The Company's cash flows from operating, investing and financing activities, as reflected in the consolidated statements of cash flows, are summarized in the following table:

	2013	2012	2011
Net cash used in operating activities	(36,432)	(27,060)	(26,245)
Net cash (used in) provided by investing activities	(2,003)	77,662	(85,422)
Net cash (used in) provided by financing activities	(8)	(5,388)	61,423

Liquidity

Ivanhoe's existing financial resources are insufficient to fund the future capital expenditures necessary to advance the development of our existing projects and to maintain the Company's business activities at their current level. In the near term, the Company will require other sources of financing in order to continue operating its business as currently constituted. Ivanhoe intends to finance its future funding requirements through a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level, and through the sale of interests in existing oil properties. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms.

These activities include discussions with a large international oil company for the creation of a joint financial participation arrangement in respect of its Pungarayacu project in Ecuador. The transaction contemplated by these discussions, if and when consummated, would be expected to generate additional cash. While progress in reaching the transaction objective has been made by the potential transaction participants, there is no assurance that the objective can be achieved, or achieved in a timely manner or that such participation will be approved by regulatory authorities in Ecuador. Without timely access to a sufficient source of financing to enable the Company to make its planned capital expenditures and otherwise fund the cost of carrying on its business, the Company may have to significantly curtail its existing business activities and may be unable to continue as a going concern.

Operating Activities

Net cash used in operating activities in 2013 was $36.4 million, an increase of $9.4 million from $27.0 million of net cash used in operating activities in 2012. The increase is primarily due to $6.9 million in increased cash G&A expenses as discussed above less non-cash share-based compensation expense and $2.5 million in other net changes impacting operating activities, which includes a net decrease of $1.1 million due to taxes, closing costs and the previous year's results related to the discontinued operations in China.

The impact on net cash used in operating activities in 2013 compared to 2012 discussed above is summarized in the following table:

	2013	2012	Change
Cash taxes paid related to discontinued operations	(7,455)	–	(7,455)
General and administrative expense less non-cash share-based compensation expense	(34,547)	(27,647)	(6,900)
Cash transaction costs paid related to discontinued operations	(2,072)	–	(2,072)
Net cash provided by operating activities of discontinued operations	(3,372)	–	(3,372)
Other net items impacting net cash used in operating activities	(3,022)	587	(3,609)
Zitong cash proceeds received	8,810	–	8,810
PCR cash proceeds received	5,226	–	5,226

Net cash used in operating activities	(36,432)	(27,060)	(9,372)

Net cash used in operating activities in 2012 was $27.0 million, an increase of $0.8 million from $26.2 million of net cash used in operating activities in 2011. The increase was mainly due to higher interest costs in 2012 from financing operations with a higher amount of debt than the prior year and was partially offset by lower general and administrative costs.

Investing Activities

E&E Expenditures

E&E capital expenditures in 2013 were $15.9 million. The Company's Canada segment spent $7.5 million on a seismic and drilling program that will provide further information for initial development on the Tamarack Project including determining

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optimal well pair locations. In Ecuador, $8.4 million was spent on environmental work, road work and in drilling of the IP-14b appraisal well.

E&E capital expenditures in 2012 were $40.1 million. In Canada, Ivanhoe spent $3.8 million to support the regulatory process at Tamarack and $23.4 million in drilling costs for the IP-17 exploration well in the southern part of Block 20 in Ecuador. Capitalized costs of $19.9 million associated with the IP-17 well were expensed in the third quarter as non-commercial quantities of hydrocarbons were discovered. Certain costs related to IP-17 remain capitalized as the well may be used in future development. In Asia, the Company spent $12.4 million for the seismic program at Zitong and $0.5 million on other expenditures.

E&E capital expenditures in 2011 were $37.4 million. In Ecuador, the Company spent $10.7 million primarily to complete a 190-kilometre 2-D seismic survey of Block 20. In Canada, $6.3 million in engineering and environmental costs were spent to support the regulatory process at Tamarack. In the Nyalga basin of Mongolia, $3.3 million in costs were incurred. Expenditures incurred on the Company's first exploration well at N16-1E-1A were expensed. The drilling rig was mobilized to a second site, N16-2E-B, and drilling commenced in the middle of September 2011. In China, capital expenditures in 2011 were $17.1 million. The Yixin-2 and Zitong-1 gas wells at the Company's Zitong project in China were tested and fracture stimulated.

Property, Plant and Equipment Expenditures
Property, Plant and Equipment ("PP&E") capital expenditures in 2013 were $1.1 million related to office and computer equipment as well as leasehold improvements.

PP&E capital expenditures in 2012 were $7.3 million. The Company drilled two wells at Dagang, one of which was completed in the second quarter of 2012; the second well was completed in the third quarter of 2012.

PP&E capital expenditures in 2011 were $13.7 million. At Dagang, four wells were drilled and completed. A well drilled in 2010 was also completed in early 2011. The fracture stimulation program at Dagang continued throughout the year.

Proceeds on Disposal of Discontinued Operations

Proceeds on disposal of discontinued operations in 2012 were approximately $131.8 million before taxes.

On December 27, 2012 Sunwing Zitong Energy, a wholly owned subsidiary of the Company, completed the transfer of the Company's participating interest in the Zitong Petroleum Contract to Shell. In exchange for Sunwing's interest in the Zitong Petroleum Contract, the Company received pre-tax proceeds of approximately $96.2 million. In June 2013 the customary holdback period of six months from the transaction date expired and the company received the full holdback proceeds ($5.1 million); and, in December 2013 the Company received the remaining proceeds once the China National Petroleum Corporation ("CNPC") completed its annual cost recovery audit for 2012 expenditures ($3.7 million).

On December 17, 2012 the Company completed the sale to MIE for all of the outstanding shares of its indirect, wholly owned subsidiary, Pan-China Resources Ltd. As consideration, the Company received $45.0 million in cash, less $5.4 million in adjustments and a $4.0 million holdback. The Company received $3.6 million in holdback proceeds in July 2013.

Restricted Cash

In December 2011, Ivanhoe was required to post a $20.0 million performance bond as part of the completion and signing of the supplementary agreement with CNPC. Following the disposition of the Company’s interest in the Zitong Block, the Company received the $20.0 million in cash that had been posted for the performance bond in February 2013.

Financing Activities

Net cash used in financing activities in 2013 was nil, which was $5.4 million lower compared to net cash provided in financing activities of $5.4 million in 2012.

Cash used in financing activities in 2012 was $5.4 million, an increase of $66.8 million compared to cash provided by financing activities in 2011 of $61.4 million. In December 2012, the Company secured $10.0 million in working capital which was repaid prior to December 31, 2012 along with the outstanding loans provided by UBS and ICFL subsequent to the closing of the China asset dispositions. In 2011, the Company raised $72.9 million, net of issuance costs, through the issuance of the Convertible Debentures in order to repay the Convertible Note due to Talisman on July 11, 2011, as well as operating expenses and capital expenditures. Cash proceeds of $29.9 million were also raised in 2011 through the exercise of purchase warrants and stock options.

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Capital Structure

As at December 31	2013			2012		
Long term debt	63,012	28.2	%	65,214	17.7	%
Shareholders' equity	160,277	71.8	%	302,998	82.3	%
Total capital	223,289	100.0	%	368,212	100.0	%

On April 22, 2013, the Company's shareholders approved a proposal to affect a reverse stock-split of the Company's common shares in order to regain compliance with the minimum bid price requirements set forth in the NASDAQ Listing Rules. The reverse stock-split took effect on April 25, 2013. As a result of the reverse stock-split shareholders received one new common share for every three old common shares held and an initial trading price for the new common shares above the NASDAQ minimum bid price was established thereby enabling the Company to regain compliance on May 9, 2013.

On September 6, 2013, the Company received a notification letter from the Listing Qualifications Department of the NASDAQ notifying the Company that the Company did not meet the minimum bid price requirements set forth in the NASDAQ Listing Rules and that the Company could regain compliance if at any time prior to March 5, 2014 the closing bid price of the Company's common shares was at least $1.00 for a minimum of 10 consecutive business days. For additional information, refer to the Form 8-K filed on September 12, 2013. On February 18, 2014, the Company applied to the NASDAQ for an additional compliance period of 180 days, which was granted and will expire on September 2, 2014.

CRITICAL ACCOUNTING PRINCIPLES AND ESTIMATES

The Financial Statements have been prepared in accordance with IFRS as issued by the IASB.

A detailed summary of the Company's significant accounting policies is included in Note 3 to the Financial Statements. Some of these policies involve critical accounting estimates as they require the Company to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions. The following section discusses critical accounting estimates and assumptions and how they affect the amounts reported in the Company's Financial Statements.

Intangible E&E Assets

Management must determine if intangible E&E assets, which have not yet resulted in the discovery of proved reserves, should continue to be capitalized or charged to E&E expense. When making this determination, Ivanhoe considers factors such as the Company's drilling results, planned exploration and development activities, the financial capacity of the Company to further develop the property, the ability to use the Company's HTL® technology in certain projects, lease expiries, market conditions and technical recommendations from its exploration staff.

Although the Company believes its estimates are reasonable and consistent with current conditions, internal planning and expected future operations, such estimates are subject to significant uncertainties and judgments. Ivanhoe cannot predict if an event that triggers impairment will occur, when it will occur, or how it will affect the reported asset amounts.

Impairment

Property, Plant and Equipment ("PP&E")

Prior to the sale of its producing oil and gas properties in 2012, the Company periodically assessed its oil and gas assets, or groups of assets, for impairment whenever events or changes in circumstances indicated the carrying value may not be recoverable. Among other things, an impairment may be triggered by falling oil and gas prices, a significant negative revision to reserve estimates, the inability to use the Company's HTL® technology in certain projects, changes in capital costs or the inability to raise sufficient financial resources to further develop the property.

Cash flow estimates for the Company's impairment assessments require significant assumptions about future prices and costs, production, reserves volumes and discount rates, as well as potential benefits from the application of its HTL® technology. Given the significant assumptions required and the likelihood that actual conditions will differ, the assessment of impairment of oil and gas assets was considered to be a critical accounting estimate.

Intangible Technology Assets

The Company's intangible technology assets consist of an exclusive, irrevocable license to deploy its HTL® technology. Ivanhoe annually reviews the technology assets, and the associated FTF assets recorded within PP&E, for impairment or

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if an adverse event or change occurs. Indicators of adverse events could include HTL® patent expiries or advancements of new technologies. The intangible asset impairment is a critical accounting estimate because it requires Ivanhoe to make assumptions about competitive technological developments, the successful commercialization of its HTL® technology and future cash flows from the HTL® technology.

Ivanhoe cannot predict if an event that triggers impairment will occur, when it will occur, or how it will affect the reported asset amounts. Although the Company believes its estimates are reasonable and consistent with current conditions, internal planning and expected future operations, such estimates are subject to significant uncertainties and judgments.

Oil and Gas Reserves

The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production becomes available and as economic conditions impacting oil and gas prices and costs change. Such revisions could be upwards or downwards. For details on our reserve estimation process, refer to the section titled "Reserves, Production and Related Information" in Items 1 and 2 of this Annual Report. Reserve estimates have a material impact on the Company's impairment evaluations, which in turn have a material impact on earnings (loss).

Option Pricing Model

The Company uses the Black-Scholes option pricing model to measure the fair value of stock options and equity settled Restricted Share Units ("RSUs") on the date of grant. Determining the fair value of stock-based awards on the grant date requires judgment, including estimating the expected life of the award, the expected volatility of the Company's common shares and expected dividends. In addition, judgment is required to estimate the number of awards that are expected to be forfeited. Changes in assumptions can materially affect the estimated fair value, and therefore, the existing models do not necessarily provide precise measures of fair value.

Deferred Income Taxes

Ivanhoe operates in a specialized industry and in several tax jurisdictions. As a result, the Company's income is subject to various rates of taxation. The breadth of the Company's operations and the global complexity of tax regulations require assessments of uncertainties and judgments in estimating the taxes that the Company will ultimately pay. The final taxes paid are dependent upon many factors, including negotiations with taxation authorities in various jurisdictions, uncertain tax positions and resolution of disputes arising from federal, provincial, state and local tax audits.

The deferred income tax liability is a critical accounting estimate because it requires Ivanhoe to make assumptions about the resolution of these uncertainties and the associated final taxes may result in adjustments to the Company's tax assets and tax liabilities.

Provisions for Decommissioning and Restoration Costs

The Company recognizes liabilities for the future decommissioning and restoration of E&E assets and PP&E. Management applies judgment in assessing the existence and extent of the Company's decommissioning and restoration obligations at the end of each reporting period, as well as in determining whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying the Company's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in prices. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

The fair value of these provisions is estimated by discounting the expected future cash outflows using a credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expense based on the discount rate.

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NEW ACCOUNTING PRONOUNCEMENTS

The Company has reviewed new and revised accounting pronouncements listed below, that have been issued, but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

IFRS 9 Financial Instruments ("IFRS 9")

The first phase of IFRS 9 was issued in November 2009 and is intended to replace IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39"). IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, as opposed to the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments given its business model and the contractual cash flow characteristics of the financial assets. The standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. During 2013, the IASB decided that a mandatory date of January 1, 2015 would not allow sufficient time for entities to prepare to apply the new standard because the impairment phase of the project has not yet been completed. Accordingly, the IASB decided that a new date should be decided upon when the entire IFRS 9 project is closer to completion. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

OFF-BALANCE SHEET ARRANGEMENTS

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed in varying degrees to normal market risks inherent in the oil and gas industry, including foreign currency exchange rate risk, credit risk and liquidity risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

FOREIGN CURRENCY EXCHANGE RATE RISK

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of our activities are transacted in or referenced to US dollars, including capital spending in Ecuador and ongoing FTF operations. Some of the Canada exploration activities are funded in Canadian dollars and the Convertible Debentures were issued in Canadian dollars in 2011. The Company did not enter into any foreign currency derivatives in 2013, nor do we anticipate using foreign currency derivatives in 2014. To help reduce the Company's exposure to foreign currency exchange rate risk, it seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company's exposure to foreign currency exchange rate risk on its net loss and comprehensive loss for 2013, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	10% Increase or Weakening	10% Decrease or Strengthening
Canadian dollar	(336)	336

CREDIT RISK

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables. The Company's maximum exposure to credit risk at December 31, 2013 is represented by the carrying amount of these non-derivative financial assets.

The Company believes its exposure to credit risk related to cash and cash equivalents, as well as restricted cash, is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments.

Long term value-added tax receivable from the Ecuadorian government will be recoverable upon commencement of commercial operations or upon the completion of the sale of the joint venture interest currently contemplated by the Company in respect of the Pungarayacu project. Ivanhoe considers the risk of default on this to be low due to the Company's ongoing operations in Ecuador.

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LIQUIDITY RISK

Liquidity risk is the risk that suitable sources of funding for the Company's business activities may not be available. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with a combination of strategic investors and/or public and private debt and equity markets, either at the parent company level or at the project level or from the sale of existing assets. There is no assurance that we will be able to obtain such financing or obtain it on favorable terms.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Ivanhoe Energy Inc.

We have audited the accompanying consolidated financial statements of Ivanhoe Energy Inc. and subsidiaries (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2013 and December 31, 2012, and the consolidated statements of loss and comprehensive loss, statements of changes in equity and statements of cash flows for each of the years in the three-year period ended December 31, 2013, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2013 and 2012 and their financial performance and cash flows for each of the years in the three-year period ended December 31, 2013, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Emphasis of Matter

Without modifying our opinion, we draw attention to Note 1 in the consolidated financial statements which indicates that as at December 31, 2013, the Company had an accumulated deficit of $458.7 million, and working capital surplus of $19.2 million, excluding assets held for sale, and during the year ended December 31, 2013, cash used in operating activities was $36.4 million and the Company expects to incur further losses in the development of its business. These conditions, along with other matters as set forth in Note 1, indicate the existence of a material uncertainty that casts substantial doubt about the Company's ability to continue as a going concern.

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Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 17, 2014 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte LLP
Chartered
Accountants

March 17, 2014
Calgary, Canada

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CONSOLIDATED FINANCIAL STATEMENTS

IVANHOE ENERGY INC.
Consolidated Statements of Financial Position

(US$000s)	Note	December 31, 2013	December 31, 2012
Assets			
Current Assets			
Cash and cash equivalents		23,556	62,819
Restricted cash	5	500	20,500
Accounts receivable	6, 10	534	14,848
Prepaid and other		942	1,593
Assets held for sale	6	51,929	–
		77,461	99,760
Intangible assets	7	152,823	285,311
Property, plant and equipment	8	1,066	10,205
Long term receivables	10	603	6,551
Note receivable		220	230
		232,173	402,057
Liabilities and Shareholders’ Equity			
Current Liabilities			
Accounts payable and accrued liabilities	10, 21	6,295	14,436
Income taxes	6, 13	–	1,720
		6,295	16,156
Long term debt	9	63,012	65,214
Long term derivative instruments	10, 11	–	181
Long term provisions	12	2,589	3,157
Deferred income taxes	13	–	14,351
		71,896	99,059
Shareholders’ Equity			
Share capital	15	586,358	586,108
Contributed surplus	15	32,614	29,759
Accumulated deficit		(458,695)	(312,869)
		160,277	302,998
		232,173	402,057
Nature of operations and going concern	1		

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Loss and Comprehensive Loss

(US$000s, except share and per share amounts)	Note	Year Ended December 31, 2013	2012	2011
Interest and other income		427	28	572
Expenses and other				
Operating		4,426	4,252	4,561
General and administrative		38,068	31,149	38,579
Exploration and evaluation	7	15,381	22,994	2,774
Impairment of intangible assets	7	92,153	–	–
Impairment of property, plant and equipment	8	8,943	–	–
Depreciation	8	1,014	961	1,014
Foreign currency exchange (gain) loss		(3,656)	1,247	(534)
Derivative instruments gain	10	(177)	(1,430)	(13,148)
Finance	9	2,340	4,328	361
Gain on derecognition of long term provision		–	–	(1,900)
Loss on debt repayment		–	2,977	–
		158,492	66,478	31,707
Net loss before income taxes		(158,065)	(66,450)	(31,135)
(Provision for) recovery of income taxes				
Current	13	(41)	–	(7)
Deferred	13	14,352	2,432	4,381
		14,311	2,432	4,374
Net loss and total comprehensive loss from continuing operations		(143,754)	(64,018)	(26,761)
Net income (loss) and total comprehensive income (loss) from discontinued operations	6	(2,072)	49,644	1,485
Net loss and total comprehensive loss		(145,826)	(14,374)	(25,276)
Net (loss) income per common share, basic and diluted				
From continuing operations		(1.25)	(0.56)	(0.23)
From discontinued operations		(0.02)	0.43	0.01
From net loss		(1.27)	(0.13)	(0.22)
Weighted average number of common shares				
Basic and diluted (000s)		114,785	114,713	114,226

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Changes in Equity

(US$000s, except share amounts)	Note	Share Capital Shares (000s)	Share Capital Amount	Contributed Surplus	Accumulated Deficit	Total
Balance December 31, 2010		111,455	550,562	23,141	(273,219)	300,484
Net loss and comprehensive loss		–	–	–	(25,276)	(25,276)
Shares issued for services		56	335	–	–	335
Exercise of stock options	16	328	4,164	(2,231)	–	1,933
Exercise of purchase warrants	15	2,874	31,047	–	–	31,047
Share-based compensation expense	16	–	–	5,614	–	5,614
Balance December 31, 2011		114,713	586,108	26,524	(298,495)	314,137

(US$000s, except share amounts)	Note	Share Capital Shares (000s)	Share Capital Amount	Contributed Surplus	Accumulated Deficit	Total
Balance December 31, 2011		114,713	586,108	26,524	(298,495)	314,137
Net loss and comprehensive loss		–	–	–	(14,374)	(14,374)
Funding of equity-settled share-based awards		–	–	(54)	–	(54)
Share-based compensation expense	16	–	–	3,289	–	3,289
Balance December 31, 2012		114,713	586,108	29,759	(312,869)	302,998

(US$000s, except share amounts)	Note	Share Capital Shares (000s)	Share Capital Amount	Contributed Surplus	Accumulated Deficit	Total
Balance December 31, 2012		114,713	586,108	29,759	(312,869)	302,998
Net loss and comprehensive loss		–	–	–	(145,826)	(145,826)
Funding of equity-settled share-based awards		–	–	(132)	–	(132)
Share-based compensation expense	16	111	250	2,987	–	3,237
Balance December 31, 2013		114,824	586,358	32,614	(458,695)	160,277

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Consolidated Statements of Cash Flows

(US$000s)	Note	Year Ended December 31, 2013	2012	2011
Operating Activities				
Net loss		(145,826)	(14,374)	(25,276)
Adjustments to reconcile net loss to cash from operating activities				
Depletion and depreciation	8	1,014	7,642	8,030
Exploration and evaluation expense	7	15,381	22,994	–
Impairment of intangible assets	7	92,153	–	–
Impairment of property, plant and equipment	8	8,943	–	–
Share-based compensation expense	16	3,521	3,502	5,883
Unrealized foreign currency exchange loss (gain)		(3,379)	800	(446)
Unrealized derivative instruments gain	10	(177)	(1,613)	(12,965)
Current income tax expense	6, 13	41	1,720	2,122
Deferred income tax recovery		(14,352)	(3,422)	(3,392)
Finance expense		2,340	4,328	361
Financing costs		–	–	269
Derecognition of long term provision		–	–	(1,900)
Pre-tax gain on disposal of discontinued operations	6	–	(57,007)	–
Loss on debt repayment		–	2,977	–
Other		31	39	50
Current income tax paid		(1,761)	(641)	(1,481)
Interest paid		(1,027)	(3,428)	(333)
Share-based payments		(188)	(166)	–
Changes in non-cash working capital items	20	6,854	9,589	2,833
Net cash used in operating activities		(36,432)	(27,060)	(26,245)
Investing Activities				
Intangible expenditures		(15,871)	(40,112)	(37,390)
Property, plant and equipment expenditures		(1,056)	(7,332)	(13,670)
Proceeds on disposal of discontinued operations	6	–	131,755	–
Restricted cash		20,000	–	(20,500)
Long term receivables		(955)	(2,606)	(1,536)
Interest paid		(2,936)	(5,693)	(4,011)
Changes in non-cash working capital items	20	(1,185)	1,650	(8,315)
Net cash provided by (used in) investing activities		(2,003)	77,662	(85,422)
Financing Activities				
Debt proceeds, net of transaction costs		–	64,644	72,914
Repayment of debt		–	(70,000)	(41,421)
Proceeds from exercise of options and warrants		–	–	29,873
Changes in non-cash working capital items	20	(8)	(32)	57
Net cash (used in) provided by financing activities		(8)	(5,388)	61,423
		(820)	715	(1,183)

Foreign exchange gain (loss) on cash and cash equivalents held in a foreign currency			
Increase (decrease) in cash and cash equivalents, for the year	(39,263)	45,929	(51,427)
Cash and cash equivalents, beginning of year	62,819	16,890	68,317
Cash and cash equivalents, end of year	23,556	62,819	16,890

(See accompanying Notes to the Consolidated Financial Statements)

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IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(tabular amounts in US$000s, except share and per share amounts)

1. NATURE OF OPERATIONS AND GOING CONCERN

Ivanhoe Energy Inc. (the "Company" or "Ivanhoe") is a publicly listed limited liability company incorporated under the laws of Yukon, Canada. Ivanhoe's common shares are listed on the Toronto Stock Exchange ("TSX") and the NASDAQ Stock Market ("NASDAQ"). The principal corporate office of Ivanhoe is located at 999 Canada Place, Suite 654, Vancouver, British Columbia, V6C 3E1. Our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9 and our operational headquarters are located at 101-6th Avenue SW, 19th Floor, Calgary, Alberta, T2P 3P4.

Ivanhoe is an independent international heavy oil development company focused on pursuing long term growth in its reserves and production. Ivanhoe plans to utilize advanced technologies, such as its patented Heavy-to-Light ("HTL®") technology, that are designed to improve recovery of heavy oil resources. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production of oil.

The December 31, 2013 consolidated financial statements ("Financial Statements") have been prepared using International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to a going concern, which contemplates the realization of assets and settlement of liabilities in the normal course of business as they become due and assumes that Ivanhoe will be able to meet its obligations and continue operations for at least its next fiscal year. Realization values may be substantially different from carrying values as shown and these Financial Statements do not give effect to adjustments that may be necessary to the carrying values and classification of assets and liabilities should the Company be unable to continue as a going concern. Such adjustments could be material.

At December 31, 2013, Ivanhoe had an accumulated deficit of $458.7 million and a working capital surplus of $19.2 million excluding assets held for sale. For the year ended December 31, 2013, cash used in operating activities was $36.4 million and the Company expects to incur further losses in the development of its business. Continuing as a going concern is dependent upon attaining future profitable operations to repay liabilities arising in the normal course of operations and accessing additional capital to develop the Company's properties. Ivanhoe intends to finance its future funding requirements through a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level, and through the sale of interests in existing oil properties. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms. Without access to additional financing or other cash generating activities in 2014, there is material uncertainty that casts substantial doubt upon the Company's ability to continue as a going concern.

The December 31, 2013 Financial Statements were approved by the Board of Directors and authorized for issue on March 14, 2014.

The Financial Statements are presented in US dollars and all values are rounded to the nearest thousand dollars except where otherwise indicated.

2. BASIS OF PRESENTATION

2.1 Statement of Compliance

The Financial Statements have been prepared in accordance with IFRS as issued by the IASB. The Financial Statements are not subject to qualification relating to the application of IFRS as issued by the IASB.

2.2 Basis of Presentation

The Financial Statements have been prepared on an historical cost basis, except derivative instruments, which are measured at fair value as explained in the Company's significant accounting policies set out in Note 3.

3. SIGNIFICANT ACCOUNTING POLICIES

3.1 Basis of Consolidation

The Financial Statements incorporate the financial statements of the Company, its subsidiaries, all of which are wholly owned, and special purpose entities that are controlled by the Company. All intercompany balances, transactions, revenue and expenses are eliminated on consolidation. The consolidated accounts are prepared using uniform accounting policies.

3.2 Foreign Currency Translation

The Company and its subsidiaries' reporting currency and the functional currency of its operations is the US dollar as this is the principal currency of the economic environments in which they operate.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect on the date of the statement of financial position. Non-monetary assets and liabilities, as well as operating transactions, are translated at the exchange rate prevailing at the time of the transaction. Translation gains and losses are reflected in earnings.

3.3 Cash and Cash Equivalents

Cash and cash equivalents includes cash on hand, deposits at banks, restricted cash and short term highly liquid investments with original maturities of three months or less.

3.4 Restricted Cash

Restricted cash balances that are not expected to be released within three months or less are reported separately from restricted cash balances included in cash and cash equivalents.

3.5 Intangible Assets

i. Exploration and Evaluation Assets

Costs of exploring for, and evaluating, oil and gas properties are initially capitalized as intangible exploration and evaluation assets ("E&E assets"). Costs may include license fees, technical studies, seismic programs, exploratory drilling and directly attributable general and administrative costs. Interest on borrowings incurred to finance qualifying E&E assets is capitalized.

If E&E assets result in sufficient proved reserves to justify commercial production and technical feasibility can be established, the assets will be tested for impairment and reclassified as property, plant and equipment ("PP&E"). If E&E assets result in sufficient reserves to justify commercial production, but those reserves cannot be classified as proved, the assets will be tested for impairment and continue to be capitalized as intangible assets as long as progress is being made to assess the reserves and economic viability of the well and/or related project. If sufficient reserves cannot be established, the corresponding E&E assets are charged to exploration and evaluation expense ("E&E expense").

E&E assets which may be attributable to a broad exploration area, such as license fees, technical studies or seismic programs, will be reclassified to PP&E or charged to E&E expense to best reflect the nature of the assets. Costs incurred prior to establishing the legal right to explore an area are charged to E&E expense as incurred.

ii. Technology Assets

The Company's HTL® technology intellectual property ("Technology Assets") consist of an exclusive, irrevocable license to deploy its HTL® technology. Technology Assets are measured at cost and classified as an intangible asset. Amortization of the Technology Assets will commence when the technology is available for use in field operations.

iii. Derecognition

An intangible asset is derecognized on disposal or when no future economic benefits are expected from use or disposal. Gains or losses arising from derecognition are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognized in profit or loss when the intangible asset is derecognized.

3.6 Property, Plant and Equipment

i. Oil and Gas Property and Equipment

PP&E is reported at cost less accumulated depletion, depreciation and accumulated impairment losses. PP&E may include the purchase price, reclassified E&E assets, any costs directly attributable to bringing the asset to the location and condition necessary for its intended use and decommissioning costs. Interest on borrowings incurred to finance qualifying PP&E is capitalized until the asset is capable of fulfilling its intended use.

PP&E is depleted using the unit-of-production method based on proved plus probable reserves, taking into account associated future development costs. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis at a ratio of six thousand cubic feet of natural gas for one barrel of oil. Depletion rates are updated annually unless there is a material change in circumstances, in which case they would be updated more frequently.

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ii. Other Assets

Furniture and equipment are depreciated on a straight-line basis over the estimated useful life of the respective assets, ranging from three to five years. The Feedstock Test Facility ("FTF") is depreciated over its expected economic life of 20 years.

3.7 Assets Held for Sale and Discontinued Operations

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This classification is required when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset, the asset must be actively marketed for sale at a price that is reasonable in relation to its fair value and the sale is expected to be completed within one year.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of loss in the period measured. Non-current assets held for sale are presented in current assets within the consolidated statement of financial position. Assets held for sale are not depleted, depreciated or amortized.

Unless otherwise indicated, information presented in the notes to the financial statements relates only to the Company's continuing operations. Information related to discontinued operations is included in Note 6 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

3.8 Impairment

The Company periodically assesses tangible and intangible assets or groups of assets for impairment annually or earlier whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. Individual assets are grouped into cash generating units for impairment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets.

If indicators of impairment exist, the recoverable amount of the asset group is estimated. An asset group's recoverable amount is the higher of its fair value less costs to sell and its value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the asset. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

Previously recognized impairment losses are reversed if there has been a change in the estimates used to determine the asset group's recoverable amount. If that is the case, the carrying amount of the asset group is increased to its revised recoverable amount which cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized in prior periods. Such a reversal is recognized in earnings. Subsequent to a reversal of impairment, the depletion or depreciation expense is adjusted in future periods to allocate the asset group's revised carrying amount, less any residual value, over its remaining useful life.

3.9 Decommissioning Provision

The Company recognizes a provision for decommissioning costs when it has an obligation to dismantle and remove its PP&E or restore the site on which it is located. The provision is estimated as the present value of the expected future expenditures, determined in accordance with local conditions and requirements, discounted at a risk-free rate. A corresponding amount is added to the carrying value of the related asset and is amortized as an expense over the economic life of the asset. The carrying amount of the provision is increased for the passage of time and adjusted for changes to the current market-based discount rate, amount and/or timing of the underlying cash flows needed to settle the obligation. Actual decommissioning costs incurred reduce the obligation. Any difference between the recorded decommissioning provision and the actual costs incurred is recorded as a gain or loss in the settlement period.

3.10 Provisions and Contingencies

Provisions are recognized when the Company has a present obligation (legal or constructive) that has arisen as a result of a past event and it is probable that a future outflow of resources will be required to settle the obligation, provided that a reliable estimate can be made of the amount of the obligation.

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Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. When it is appropriate to discount a provision, the increase in the provision due to passage of time is recognized as interest expense.

3.11 Financial Assets

Financial assets are classified as i) loans and receivables, ii) available-for-sale, iii) financial assets at fair value through profit or loss, or iv) held-to-maturity. Ivanhoe determines the classification of its financial assets upon initial recognition. Financial assets are recognized initially at fair value and subsequent measurement depends upon their classification.

i. Loans and Receivables

Loans and receivables are non-derivative financial assets, with fixed or determinable payments, that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. The Company's cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables are classified as loans and receivables.

ii. Available-for-Sale

Available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income. Accumulated changes in fair value are recorded as a separate component of equity until the investment is derecognized or impaired. The Company does not currently have any financial assets classified as available for sale.

iii. Financial Assets at Fair Value Through Profit or Loss

Financial assets are classified as fair value through profit or loss ("FVTPL") when the financial asset is held for trading or it is designated as FVTPL. Financial assets classified as FVTPL are measured at fair value with unrealized gains and losses recognized through earnings. The Company currently does not have any financial assets classified at FVTPL.

iv. Held-to-Maturity

Held-to-maturity investments are non-derivative financial assets with fixed or determinable payments and fixed maturity dates that the Company has the intent and ability to hold to maturity. These investments are recognized on a trade date basis and are subsequently measured at amortized cost using the effective interest method. The Company does not currently have any financial assets classified as held-to-maturity.

v. Impairment

Financial assets, other than those at FVTPL, are assessed for indicators of impairment annually. Financial assets are impaired when there is evidence that the estimated future cash flows of the investment have been impacted. For financial assets carried at amortized cost, the amount of the impairment is the difference between the asset's carrying amount and the present value of the estimated future cash flows, discounted at the financial asset's original effective interest rate.

The carrying amount of all financial assets, excluding accounts receivables, is directly reduced by the impairment loss. The carrying amount of accounts receivable is reduced through the use of an allowance account. Subsequent recoveries of amounts previously written off are recorded against the allowance account. Changes in the carrying amount of the allowance account are recognized in earnings.

With the exception of available-for-sale equity instruments, which are revalued through other comprehensive income, if, in a subsequent period, the amount of the impairment loss decreases and the decrease relates to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed through earnings. On the date of the impairment reversal, the carrying amount of the financial asset cannot exceed its amortized cost had it not been impaired.

vi. Derecognition

Financial assets are derecognized when the rights to receive cash flows from the investments have expired, or have been transferred, and the Company has transferred substantially all risks and rewards of ownership.

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3.12 Financial Liabilities

Financial liabilities are classified as i) financial liabilities at FVTPL or ii) as other financial liabilities measured at amortized cost. Ivanhoe determines the classification of its financial liabilities upon initial recognition. The measurement of financial liabilities depends on their classification.

i. Financial Liabilities at Fair Value Through Profit or Loss

Financial liabilities classified as FVTPL include financial liabilities held for trading and financial liabilities designated upon initial recognition as FVTPL. Derivatives, including bifurcated embedded derivatives, are also classified as FVTPL. Changes in the fair value of financial liabilities classified as FVTPL are recognized through earnings. The Company's derivative instruments are classified as financial liabilities at FVTPL.

ii. Other Financial Liabilities

Financial liabilities classified as other financial liabilities are initially recognized at fair value less directly attributable transaction costs. After initial recognition, other financial liabilities are measured at amortized cost using the effective interest method. The Company's accounts payable and accrued liabilities, long term debt and long term provisions are classified as other financial liabilities.

3.13 Oil and Gas Revenue

Sales of oil and gas production are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. Oil and gas revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

3.14 Income Tax

Income tax expense represents the sum of tax currently payable and deferred tax.

i. Current income tax

Income tax assets and liabilities are measured at the amount expected to be recovered from, or paid to, the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the date of the statement of financial position.

ii. Deferred income tax

Using the liability method, deferred income tax is provided for on taxable and deductible differences between the tax basis of assets and liabilities in comparison to their carrying amounts for financial reporting purposes.

Deferred income tax liabilities are recognized for all taxable temporary differences, except:

— where the deferred income tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss; and

— in respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred income tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized except:

— where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

— in respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

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The carrying amount of deferred tax assets is reviewed at each date of the statement of financial position and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all, or part, of the deferred income tax asset to be utilized. Unrecognized deferred income tax assets are reassessed at each date of the statement of financial position and are recognized to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is expected to be realized or the liability is expected to be settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the date of the statement of financial position.

Deferred income tax relating to items recognized directly in equity is recognized in equity and not in earnings.

Deferred income tax assets and deferred income tax liabilities are offset if, and only if, a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities which intend to either settle current tax liabilities and assets on a net basis, or to realize the assets and settle the liabilities simultaneously, in each future period in which significant amounts of deferred tax assets or liabilities are expected to be settled or recovered.

iii. Uncertain tax positions

The Company is subject to taxation in numerous jurisdictions. The Company may enter into transactions or perform calculations during the course of business for which the ultimate tax determination may be uncertain. The Company maintains provisions for uncertain tax positions that it believes appropriately reflect its risk. These provisions are made using the best estimate of the amount expected to be paid based on a qualitative assessment of all relevant factors. The Company reviews the adequacy of these provisions at the end of the reporting period. However, it is possible that at some future date, liabilities in excess of the Company’s provisions could result from audits by, or litigation with, tax authorities. Where the final outcome of these tax-related matters is different from the amounts that were initially recorded, such differences will affect the tax provisions in the period in which such determination is made.

3.15 Borrowing Costs

For qualifying assets, which take a substantial period of time to become ready for intended use, interest on borrowings incurred to finance E&E assets and PP&E is capitalized until the asset is capable of fulfilling its intended use. Capitalized borrowing costs cannot exceed the actual interest and financing costs incurred. All other interest and financing costs are recognized in earnings in the period in which they are incurred.

3.16 Share-Based Payments

Equity settled share-based payments in the form of stock options and restricted share units (“RSUs”) granted to directors, employees and those providing similar services to Ivanhoe and its subsidiaries, are measured at fair value on the grant date and expensed on a graded basis over the vesting period of each annual installment. The cumulative expense for equity settled transactions incorporates a forfeiture rate to reflect the Company’s best estimate of the number of equity instruments that will ultimately vest.

Cash settled share-based payments, such as the RSUs granted to eligible employees, are measured at fair value on the grant date and are re-valued at each subsequent reporting period until vested. The awards are expensed on a graded basis over the vesting period of each annual installment. A forfeiture rate is applied in the same manner as described for equity settled awards. No expense is recognized for awards that do not ultimately vest.

Shares issued from the stock bonus plan are measured at fair value on the grant date.

3.17 Income or Loss per Common Share

Basic net income or loss per common share is computed by dividing net income or loss by the weighted average number of common shares outstanding during the period. Diluted net income per common share amounts are calculated based on net income divided by dilutive common shares. Dilutive common shares are arrived at by adding common shares issuable on exercise of options or purchase warrants to weighted average common shares, assuming that proceeds received from the exercise of in-the-money stock options and purchase warrants are used to purchase common shares at the average market price; dilution from the Company's convertible debt is considered using the "if converted" method.

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3.18 Changes in Accounting Policy and Disclosure

i. IFRS 10 Consolidated Financial Statements (“IFRS 10”)

IFRS 10 was issued in May 2011 and sets a single basis for consolidation, that being control of an entity. IFRS 10 replaces portions of IAS 27, “Consolidated and Separate Financial Statements” and Standing Interpretations Committee 12, “Special Purpose Entities” that provide a single model on how entities should prepare consolidated financial statements. This standard was effective for reporting periods on or after January 1, 2013, with earlier adoption permitted. There were no changes to the consolidated financial statements as a result of the adoption of this standard.

ii. IFRS 11 Joint Arrangements (“IFRS 11”)

IFRS 11, issued in May 2011, establishes principles for financial reporting by entities involved in a joint arrangement and distinguishes between joint operations and joint ventures. IFRS 11 supersedes the current IAS 31, “Interests in Joint Ventures” and Standing Interpretations Committee 13, “Jointly Controlled Entities-Non Monetary Contributions by Venturers”. This standard was effective for reporting periods on or after January 1, 2013, with earlier adoption permitted. There were no changes to the consolidated financial statements as a result of the adoption of this standard.

iii. IFRS 12 Disclosure of Interests in Other Entities (“IFRS 12”)

IFRS 12, issued in May 2011, establishes a single set of disclosure objectives, and requires minimum disclosures designed to meet those objectives, regarding interests in subsidiaries, joint arrangements, associates or unconsolidated structured entities. IFRS 12 is intended to combine the disclosure requirements on interests in other entities currently located throughout different standards. This standard was effective for reporting periods on or after January 1, 2013, with earlier adoption permitted. There were no changes to the consolidated financial statements as a result of the adoption of this standard.

iv. IFRS 13 Fair Value Measurements (“IFRS 13”)

IFRS 13, issued in May 2011, defines fair value, sets out a single IFRS framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to IFRS that require or permit fair value measurements or related disclosures, except in specified circumstances. This standard was effective for reporting periods on or after January 1, 2013, with earlier adoption permitted. There were no changes to the consolidated financial statements as a result of the adoption of this standard.

v. IAS 28 Investments in Associates and Joint Ventures (“IAS 28”)

IAS 28 was amended in 2011 and prescribes the accounting for investments in associates and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. This standard was effective for reporting periods on or after January 1, 2013, with earlier adoption permitted. There were no changes to the consolidated financial statements as a result of the adoption of this standard.

3.19 Standards and Interpretations Issued But Not Yet Adopted

The Company has reviewed new and revised accounting pronouncements listed below that have been issued, but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

i. IFRS 9 Financial Instruments (“IFRS 9”)

The first phase of IFRS 9 was issued in November 2009 and is intended to replace IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”). IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, as opposed to the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments given its business model and the contractual cash flow characteristics of the financial assets. The standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. During 2013, the IASB decided that a mandatory date of January 1, 2015 would not allow sufficient time for entities to prepare to apply the new standard because the impairment phase of the project has not yet been completed. Accordingly, the IASB decided that a new date should be decided upon when the entire IFRS 9 project is closer to completion. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

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4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The preparation of financial statements in accordance with IFRS requires management to make estimates and assumptions in certain circumstances that affect reported amounts. The most sensitive estimates affecting the Financial Statements are in the areas set out below. Actual results may differ from these estimates.

4.1 Critical Judgments in Applying Accounting Policies

i. E&E Assets

Management must determine if E&E assets, which have not yet resulted in the discovery of proved reserves, should continue to be capitalized or charged to E&E expense. When making this determination, management considers factors such as the Company's drilling results, planned exploration and development activities, the financial capacity of the Company to further develop the property, the ability to use the Company's HTL® technology in certain projects, lease expiries, market conditions and technical recommendations from its exploration staff.

ii. Impairment

a. Property, Plant and Equipment ("PP&E")

The Company periodically assesses its oil and gas assets or groups of assets for impairment or whenever events or changes in circumstances indicated the carrying value may not be recoverable. Among other things, an impairment may be triggered by changes in market conditions, a significant negative revision to reserve estimates, the inability to use the Company's HTL® technology in certain projects, changes in capital costs or the inability to raise sufficient financial resources to further develop the property. Cash flow estimates for the Company's impairment assessments require significant assumptions about future prices and costs, production, reserves volumes and discount rates, as well as potential benefits from the application of its HTL® technology.

b. Intangible Technology Assets

Ivanhoe annually reviews the intangible Technology Assets, and the associated FTF assets recorded within PP&E, for impairment or if an adverse event or change occurs. Indicators of adverse events could include HTL® patent expiries, advancements of new technologies or the inability to successfully commercialize the HTL® technology. The impairment of the Technology Assets requires management to make assumptions about competitive technological developments, the successful commercialization of the Company's HTL® technology and future cash flows from the HTL® technology.

iii. Provisions for Decommissioning and Restoration Costs

The Company recognizes liabilities for the future decommissioning and restoration of E&E assets and PP&E. Management applies judgment in assessing the existence and extent of the Company's decommissioning and restoration obligations at the end of each reporting period, as well as in determining whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying the Company's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in prices. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

The fair value of these provisions is estimated by discounting the expected future cash outflows using a credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expense based on the discount rate.

4.2 Key Sources of Estimation Uncertainty

i. HTL® Technology

Future cash flows from HTL® technology and the rate at which they are discounted are a key source of estimation uncertainty as it requires management to make assumptions about the successful commercialization of the HTL® technology and competitive technological developments. Success in commercializing the HTL® technology in the oil and gas industry depends on the Company’s ability to economically design, construct and operate commercial-scale plants and a variety of other factors. Ivanhoe expects that technological advances in the processes and procedures for upgrading heavy oil and

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bitumen into lighter, less viscous products will continue to progress. It is possible that those advances could cause the HTL® technology to become uncompetitive or obsolete.

ii. Option Pricing Models

The Company uses the Black-Scholes option pricing model to measure the fair value of stock options and equity settled RSUs on the date of grant. Determining the fair value of stock-based awards on the grant date requires judgment, including estimating the expected life of the award, the expected volatility of the Company's common shares and expected dividends. In addition, judgment is required to estimate the number of awards that are expected to be forfeited. Changes in assumptions can materially affect the estimated fair value and, therefore, the existing models do not necessarily provide precise measures of fair value.

iii. Convertible Debentures

On June 9, 2011, the Company issued Cdn$73.3 million of 5.75% convertible unsecured subordinated debentures ("Convertible Debentures"). The Canadian dollar denominated debt is considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, the Convertible Debentures were bifurcated into debt and the equity conversion option, which was recognized at fair value using the Black-Scholes valuation method. The Black-Scholes valuation method requires the input of highly subjective assumptions regarding expected volatility of the Company's share price and risk-free interest rate, and is therefore considered to be a crucial accounting estimate.

iv. Deferred Income Taxes

Ivanhoe operates in a specialized industry and in several tax jurisdictions. As a result, the Company's income is subject to various rates of taxation. The breadth of the Company's operations and the global complexity of tax regulations require assessments of uncertainties and judgments in estimating the taxes that the Company will ultimately pay. The final taxes paid are dependent upon many factors, including negotiations with taxation authorities in various jurisdictions, uncertain tax positions and resolution of disputes arising from federal, provincial, state and local tax audits. The resolution of these uncertainties and the associated final taxes may result in adjustments to the Company's tax assets and tax liabilities.

5. RESTRICTED CASH

	December 31, 2013	December 31, 2012
Ecuador Performance Bond	500	500
Zitong Performance Bond	–	20,000
	500	20,500

In December 2011, Ivanhoe was required to post a $20.0 million performance bond (the "Zitong Performance Bond") as part of the completion and signing of a supplementary agreement (the "Supplementary Agreement") to the Contract for Exploration, Development and Production in the Zitong Block (the "Zitong Petroleum Contract") with China National Petroleum Corporation ("CNPC"). In 2013, the Zitong Performance Bond was released as discussed in Note 6.2.

6. ASSETS HELD FOR SALE AND RESULTS OF DISCONTINUED OPERATIONS

6.1 Assets Held for Sale

As at December 31, 2013, the Company has been engaged in discussions with a large international oil company regarding jointly investing and participating in the development and operation of Block 20 in Ecuador. During the course of these discussions, the parties have developed a framework of commercial terms which has been used in separate discussions with the Government of Ecuador. The ultimate objective of discussions with the Government has been the establishment of mutually acceptable terms and conditions allowing for the formation of a consortium between the Company and the third party to jointly develop Block 20. If approved, the consortium contract would supplant the Company's existing contract. The formation of the consortium and the recovery of the amounts held for sale, which includes consideration for the third party to participate in the Block 20 project under a new contract, requiring the release of the existing contract, is contingent upon the successful negotiation of definitive and legally binding agreements that reflect the achievement of this objective.

During the fourth quarter of 2013, the Company met criteria to classify its E&E assets in Ecuador as held for sale. The carrying value of the assets held for sale consist of expenditures in the amount of $51.9 million, consisting of $44.9 million, $6.9 million and $0.1 million of E&E assets, VAT receivables and other assets, respectively, as at December 31, 2013.

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6.2 Zitong Block

On December 27, 2012 Sunwing Zitong Energy, a wholly owned subsidiary of the Company, completed the transfer of the Company's participating interest in the Zitong Petroleum Contract to Shell China Exploration and Production Co. ("Shell").

In exchange for Sunwing's interest in the Zitong Petroleum Contract, the Company received total pre-tax cash proceeds of $105.0 million subject to a holdback pending the completion of regulatory audits. Initial pre-tax proceeds of approximately $96.2 million were delivered on closing and the Company received the remaining proceeds during 2013.

Shell assumed the obligations under the Supplementary Agreement and will replace the Zitong Performance Bond with a new performance bond financed by Shell. As a result, the collateral for the Zitong Performance Bond, presented as restricted cash on the Company's consolidated statement of financial position, was released.

The Zitong Block was previously reported in the Asia segment.

6.3 Pan-China Resources Ltd.

On December 17, 2012 the Company completed the sale to MIE Holdings Corporation ("MIE") for all of the outstanding shares of its indirect, wholly owned subsidiary, Pan-China Resources Ltd.

As consideration, the Company received $45.0 million in cash, less $5.4 million in adjustments and a $4.0 million holdback. The Company received the holdback amount during 2013.

6.4 Results of Discontinued Operations

Analysis of the results of discontinued operations and on the disposal of the assets of the Zitong Block and Pan-China Resources Ltd., constituting the discontinued operations, is as follows:

	Year Ended December 31,		
	2013	2012	2011
Revenue	–	32,470	37,407
Expenses and other	–	35,105	32,818
Net (loss) income before tax and before disposal	–	(2,635)	4,589
Income taxes	–	3,008	3,104
Net (loss) income after tax and before disposal	–	(5,643)	1,485
Pre-tax (loss) gain on disposal	(2,072)	57,007	–
Tax on disposal	–	1,720	–
After-tax (loss) gain on disposal	(2,072)	55,287	–
Net (loss) income from discontinued operations	(2,072)	49,644	1,485

The net cash flows attributable to the operating, investing and financing activities of the discontinued operations are as follows:

	Year Ended December 31,		
	2013	2012	2011
Operating activities	(2,072)	3,372	3,748

Investing activities	–	111,909	(30,595)
Financing activities	–	–	–
Total cash flows	(2,072)	115,281	(26,847)

As at December 31, 2013, all outstanding amounts (December 31, 2012 - $14.4 million) due from counterparties in the sale of discontinued operations have been collected.

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7. INTANGIBLE ASSETS

	Exploration and Evaluation Assets					
	Asia	Canada	Latin America	Total	HTL® Technology	Total Intangible Assets
Cost						
Balance December 31, 2011	17,203	133,452	31,178	181,833	92,153	273,986
Additions	424	8,334	25,561	34,319	–	34,319
Exploration and evaluation expense	(2,968)	(159)	(19,867)	(22,994)	–	(22,994)
Balance December 31, 2012	14,659	141,627	36,872	193,158	92,153	285,311
Additions	722	11,196	7,982	19,900	–	19,900
Exploration and evaluation expense	(15,381)	–	–	(15,381)	–	(15,381)
Impairment charge	–	–	–	–	(92,153)	(92,153)
Assets reclassified as held for sale	–	–	(44,854)	(44,854)	–	(44,854)
Balance December 31, 2013	–	152,823	–	152,823	–	152,823

Exploration and evaluation costs of $15.4 million were expensed in the year ended December 31, 2013. As part of the Company's refocus of global activities, it is actively pursuing potential candidates to purchase or farm-in on the Mongolian production sharing contract ("PSC"). With the current economic conditions globally, it is not clear as to when a potential purchase or farm-in process will be successfully concluded. The Company expensed $15.4 million in capital costs for the year ended December 31, 2013 to reduce the carrying value of assets related to the Mongolian PSC to their estimated recoverable amount.

Exploration and evaluation costs of $23.0 million were expensed in the year ended December 31, 2012. The IP-17 exploratory well in the southern part of Block 20 in Ecuador led to the discovery of non-commercial quantities of hydrocarbons and the Company expensed $19.9 million in related costs. In addition, the Company also expensed $3.0 million in capital costs in 2012 relating to the second Mongolian well drilled in 2011.

The Company incurred a non-cash impairment charge of $101.1 million in 2013 of which $92.2 million related to the HTL® Technology asset and $8.9 million was related to the FTF which were recorded in intangible assets and property, plant and equipment (Note 8), respectively, on the consolidated statement of financial position and held as part of the Technology Development segment. The impairment charge reduced the recoverable amount of the asset to nil which represents its value in use.

The impairment charge for HTL® was driven, and resulted from, an escalation in the discount rate in the fourth quarter of 2013 calculated using the modified Capital Asset Pricing Model. In the fourth quarter of 2013, the Company's share price and yields from publicly traded debt required the Company to assign additional risk premiums above what the Company has historically been required to use. Considering these factors, and as required under IFRS, the Company used a discount rate at year end of approximately 26% to conduct its impairment analysis for HTL.

The Company's expected use of the HTL® technology estimates cash flows that typically have an internal rate of return lower than the discount rate of 26% used at year end which triggered the impairment charge in the period.

7.1 Security

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Company's oil sands leases comprising the Tamarack project in the Athabasca region of Canada ("Tamarack"), the Company will make a cash payment to Talisman of up to Cdn$15.0 million, as a contingent, final payment for the acquisition of the oil sands leases (Note 14). The contingent payment is secured by a first fixed charge and security interest in favor of Talisman, including over the oil sands leases, and a general security interest in all of the Company's present and subsequently acquired property other than equity interests in the Company's subsidiaries (through which it holds assets in Mongolia, Ecuador and the HTL® technology).

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8. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas Property and Equipment					
	Asia	Canada	Latin America	Total	Other Assets	Total PP&E
Cost						
Balance December 31, 2011	48,862	–	–	48,862	14,477	63,339
Additions	6,984	–	–	6,984	–	6,984
Disposals	(55,846)	–	–	(55,846)	(79)	(55,925)
Balance December 31, 2012	–	–	–	–	14,398	14,398
Additions	–	–	–	–	847	847
Impairment charge	–	–	–	–	(8,943)	(8,943)
Disposals	–	–	–	–	(80)	(80)
Balance December 31, 2013	–	–	–	–	6,222	6,222
Accumulated Depletion and Depreciation						
Balance December 31, 2011	13,095	–	–	13,095	3,265	16,360
Depletion and depreciation	6,691	–	–	6,691	961	7,652
Disposals	(19,786)	–	–	(19,786)	(33)	(19,819)
Balance December 31, 2012	–	–	–	–	4,193	4,193
Depletion and depreciation	–	–	–	–	1,014	1,014
Disposals	–	–	–	–	(51)	(51)
Balance December 31, 2013	–	–	–	–	5,156	5,156
Net Book Value						
As at December 31, 2011	35,767	–	–	35,767	11,212	46,979
As at December 31, 2012	–	–	–	–	10,205	10,205
As at December 31, 2013	–	–	–	–	1,066	1,066

8.1 Other Assets

Other assets include the Company’s FTF at the Southwest Research Institute in San Antonio, Texas, and general furniture and fixtures. During 2013, the Company recognized a non-cash impairment charge to its FTF assets as described in Note 7.

9. DEBT

9.1 Convertible Debentures

	December 31, 2013	December 31, 2012
Debt component of the Convertible Debentures	68,926	73,686
Unamortized bifurcated derivative and transaction costs	(5,914)	(8,472)
Carrying amount	63,012	65,214

On June 9, 2011, the Company issued Cdn$73.3 million in 5.75% convertible unsecured subordinated debentures at a price of Cdn$1,000 per debenture. Cdn$50.0 million of the Convertible Debentures were issued in a public offering of

Cdn$50.0 million. The remaining Cdn$23.3 million were issued in a private placement on the same terms as the public offering.

The Convertible Debentures mature on June 30, 2016, pay interest semi-annually on June 30 and December 31 and are convertible at a price of Cdn$10.08 per share. They are redeemable after June 30, 2014 at Ivanhoe's option if the current market price of Ivanhoe's common shares is equal to or greater than 125% of the conversion price. Any such redemption may be made using either cash or common shares.

The Canadian dollar denominated debt is considered an embedded derivative since the functional currency of the Company is the US dollar and, as such, the option was bifurcated and recognized at fair value as a long term derivative liability (Note 11) with changes in value recorded each period in the consolidated statement of loss.

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Interest incurred for all outstanding debt was recorded as follows:

	Year ended December 31,		
	2013	2012	2011
Interest expense(1)	2,429	4,213	333
Capitalized to E&E	4,109	5,027	2,878
Capitalized to PP&E	–	(319)	319
Total interest incurred	6,538	8,921	3,530

(1) Interest expense is included in finance expense on the consolidated statements of loss and comprehensive loss.

10. FINANCIAL INSTRUMENTS

10.1 Fair Value of Financial Instruments Measured at Amortized Cost

Except as detailed below, the fair value of the Company's financial instruments recognized at amortized cost approximates their carrying value due to the short term maturity of these instruments.

	December 31, 2013	December 31, 2012
Convertible Debentures		
Carrying amount	63,012	65,214
Fair value	31,017	60,052

The fair value of the liability component of the Convertible Debentures was estimated using the closing price of the publicly traded debentures at December 31, 2013.

10.2 Financial Instruments Measured at Fair Value Through Profit or Loss

The Company classifies its financial instruments according to the fair value hierarchy outlined in IFRS 7, Financial Instruments: Disclosures, as described below:

— Level 1 – using quoted prices in active markets for identical assets or liabilities.

— Level 2 – using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).

— Level 3 – using inputs for the asset or liability that are not based on observable market data, such as prices based on internal models or other valuation methods.

The following table presents the Company's derivative instruments measured at FVTPL:

	Level 2	Level 3	
	2011 Convertible Component of Debentures	Subsidiary Option	Total Fair Value
Balance December 31, 2011	1,617	183	1,800

Derivative gains through profit and loss	(1,430)	–	(1,430)
Foreign exchange gains	(6)	–	(6)
Expiration of subsidiary option through profit and loss	–	(183)	(183)
Balance December 31, 2012	181	–	181
Derivative gains through profit and loss	(177)	–	(177)
Foreign exchange gains	(4)	–	(4)
Balance December 31, 2013	–	–	–

The gain on derivative instruments of $0.2 million for the year ended December 31, 2013 (December 31, 2012 – $1.6 million) originated from the revaluation of derivative instruments measured at FVTPL.

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10.3 Risks Arising from Financial Instruments

Ivanhoe is exposed in varying degrees to normal market risks resulting from foreign currency exchange rate risk, credit risk, interest rate risk and liquidity risk. The Company recognizes these risks and manages its operations to minimize the exposure to the extent practicable.

i. Foreign Currency Exchange Rate Risk

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of the Company's activities are transacted in, or referenced to, US dollars, including capital spending in Ecuador and ongoing FTF operations. Some of the Canada exploration activities are funded in Canadian dollars and the Convertible Debentures were issued in Canadian dollars. The Company did not enter into any foreign currency derivatives in 2013. To help reduce the Company's exposure to foreign currency exchange rate risk, the Company seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company's exposure to foreign currency exchange rate risk on its net loss and comprehensive loss for 2013, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	Change From a 10% Increase or Weakening	Change From a 10% Decrease or Strengthening
Canadian dollar	336	(336)

ii. Credit Risk

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables. The Company's maximum exposure to credit risk at December 31, 2013, is represented by the carrying amount of these non-derivative financial assets.

The Company believes its exposure to credit risk related to cash and cash equivalents and restricted cash is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments. Most of the Company's credit exposures are with counterparties in the energy industry and are therefore exposed to normal industry credit risks. Ivanhoe manages its credit risk by entering into sales contracts only with established entities.

	December 31, 2013	December 31, 2012
Accounts receivable – current	534	14,848

iii. Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company's business activities may not be available. Since cash flows from existing operations are insufficient to fund operations and future capital expenditures, Ivanhoe intends to finance future capital projects with a combination of strategic investors and/or public and private debt and equity markets, either at the parent company level or at the project level or from the sale of existing assets. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms.

The contractual maturity of the fixed rate derivative and non-derivative financial liabilities are shown in the table below. The amounts presented represent the future undiscounted cash flows and therefore may not equate to the values presented in the statement of financial position.

As at December 31, 2013	Less than 1 year	1 to 2 years	3 to 4 years
Non-derivative financial liabilities			
Accounts payable and accrued liabilities	6,295	–	–
Debt and interest	3,963	74,854	–

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11. DERIVATIVE INSTRUMENTS

The Company issued Cdn$73.3 million in Convertible Debentures in the second quarter of 2011, as described in Note 9.1. The outstanding principal amount of the Convertible Debentures is convertible into common shares of the Company. The fair value of the equity conversion component was nil at December 31, 2013, calculated with the Black-Scholes valuation method using a risk-free interest rate of 1.21%, a dividend yield of 0.00%, a weighted average volatility factor of 40.00% and an expected life of 2.5 years.

Based on the nil balance of the equity conversion component, a 10% increase or decrease would have an immaterial effect on the fair value of the option.

12. LONG TERM PROVISIONS

	December 31, 2013	December 31, 2012
Decommissioning provision		
Balance, beginning of year	2,876	1,567
Liabilities incurred	399	950
Revisions in cash flow estimates	(563)	210
Unwinding of discount	(89)	28
Change in discount rates	(315)	121
Balance, end of year	2,308	2,876
Long term accrued liabilities	281	281
Long term provisions	2,589	3,157

12.1 Decommissioning Provision

The decommissioning provision represents the present value of decommissioning costs related to oil and gas properties in Canada, the FTF, and oil and gas properties in Ecuador, which are expected to be incurred in 2016-2035, 2029 and 2038 respectively. The Company records a provision for the estimated future cost of decommissioning oil and gas properties and the FTF on a discounted basis. The provision for the costs of decommissioning these oil and gas properties and the FTF has been estimated, using current prices and discounted using a risk-free interest rate of 1.2% to 3.2% at December 31, 2013 (December 31, 2012 – 0.9% to 2.2%).

12.2 Long term accrued liabilities

Long term accrued liabilities include share-based payments arising from cash-settled awards from the RSU plan (Note 16) and a finance lease obligation related to vehicle leases in Ecuador.

13. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rates to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2013, 2012 and 2011 were 25.0%, 25.0% and 26.5%, respectively. The sources and tax effects for the differences are as follows:

Year ended December 31,

	2013	2012	2011
Loss from continuing operations before income taxes	158,065	66,450	31,135
Combined Canadian federal and provincial statutory rates	25.0 %	25.0 %	26.5 %
Tax benefit	(39,516)	(16,613)	(8,251)
Tax losses and deferred deductions not recognized as deferred tax assets	34,944	13,036	7,456
Foreign net losses affected at higher income tax rates	(9,964)	(760)	(867)
Expiry of tax loss carry-forwards	–	791	172
Derivative and other gains not deductible (taxable)	(44)	387	(3,784)
Compensation not deductible	845	781	1,410
Net currency exchange losses (gains) not deductible (taxable)	(904)	327	(136)
Change in prior year estimate of tax loss carry-forwards	(115)	(461)	(621)
Other differences	443	80	247
Recovery of income taxes	(14,311)	(2,432)	(4,374)

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Significant components of the Company's deferred income tax assets and liabilities are as follows:

	December 31, 2013		December 31, 2012	
	Assets	Liabilities	Assets	Liabilities
Property, plant and equipment	–	–	672	(3,686)
Intangible assets	–	–	2,543	(35,786)
Tax loss carry-forwards	–	–	21,556	–
Tax credit carry-forwards	–	–	350	–
	–	–	25,121	(39,472)

As at December 31, 2013, the Company's deferred income tax liability in the consolidated statement of financial position was nil.

The Company has not recorded deferred income tax assets in respect of the following:

	December 31, 2013	December 31, 2012
Operating tax loss carry-forwards	265,539	175,655
Unrealized foreign exchange loss on intercompany debt	4,537	–
Financing costs	1,033	3,691
	271,109	179,346

The consolidated loss carry-forward amounts and the year of expiry as at December 31, 2013, are shown in the following table. A loss of approximately Cdn$83.0 million from the disposition of Russian operations in 2000 and the settlement of intercompany loans in 2012, is available for carry-forward indefinitely against future Canadian capital gains, and is not included in the deferred income tax assets above.

Year of Expiry	
2014	5,188
2015	6,732
2018	2,093
2019	1,078
2020 to 2025	5,508
2026 to 2033	311,625
	332,224

As at December 31, 2013, the Company's loss carry-forwards of $332.2 million were composed of $258.5 million in Canada and $73.7 million in the United States.

At December 31, 2013, no current income taxes are payable (December 31, 2012– $1.7 million).

14. COMMITMENTS AND CONTINGENCIES

14.1 Operating Lease Arrangements

In the year ended December 31, 2013, the Company expended $1.5 million (December 31, 2012 – $1.0 million) on operating leases relating to the rental of office space, which expire between November 2014 and August 2018.

At December 31, 2013, future net minimum payments for operating leases were:

2014	993
2015	826
2016	704
2017	352
After 2017	158
	3,033

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14.2 Other

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Tamarack leases, the Company will make a cash payment to Talisman of up to Cdn$15.0 million, as a contingent, final payment for the 2008 acquisition of the Tamarack leases.

From time to time, Ivanhoe enters into consulting agreements whereby a success fee may be payable if and when either a definitive agreement is signed or certain other contractual milestones are met. Under the agreements, the consultant may receive cash, common shares, stock options or some combination thereof. Similarly, agreements entered into by the Company may contain cancellation fees or liquidated damages provisions for early termination. These fees are not considered to be material.

The Company may provide indemnities to third parties, in the ordinary course of business, that are customary in certain commercial transactions, such as purchase and sale agreements. The terms of these indemnities will vary based upon the contract, the nature of which prevents Ivanhoe from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company's management is of the opinion that any resulting settlements relating to indemnities are not likely to be material.

In the ordinary course of business, the Company is subject to legal proceedings being brought against it. While the final outcome of these proceedings is uncertain, the Company believes that these proceedings, in the aggregate, are not reasonably likely to have a material effect on its financial position or earnings.

15. SHAREHOLDERS' EQUITY

15.1 Share Capital

Authorized	Unlimited common shares with no par value Unlimited preferred shares with no par value
Issued and Outstanding	114,824,254 common shares (December 31, 2012 – 114,713,143, December 31, 2011 – 114,713,143) Nil preferred shares (December 31, 2012 – nil, December 31, 2011 – nil)

On April 22, 2013, the Company proceeded with a three for one (the "Consolidation Ratio") common share consolidation which reduced the number of outstanding common shares from approximately 344.5 million to approximately 114.8 million. The share consolidation also resulted in proportionate adjustments to outstanding stock options and RSUs as well as an adjustment to the conversion price of the Convertible Debentures. The share consolidation also increased the loss per share amount by the Consolidation Ratio.

In 2011, cash proceeds of $29.9 million were raised through the exercise of purchase warrants and stock options.

See the Consolidated Statements of Changes in Equity for the change in common shares issued in the years ended December 31, 2013, 2012 and 2011.

15.2 Contributed Surplus

Contributed surplus at December 31, 2013, 2012 and 2011 consisted solely of share-based compensation expense from equity settled awards.

16. SHARE-BASED PAYMENTS

Share-based transactions were charged to earnings, as general and administrative or operating expenses, or capitalized to E&E assets as follows:

	Year ended December 31,		
	2013	2012	2011
Share-based expense related to			
Equity settled transactions	3,237	3,289	5,614
Cash settled transactions	284	211	269
Total share-based expense	3,521	3,502	5,883
Share-based payments capitalized as E&E assets	–	–	335

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16.1 Stock Option Plan

Details of transactions under the Company's stock option plan are as follows:

	Number of Stock Options (000s)	Weighted Average Exercise Price (Cdn$)
Outstanding, December 31, 2010	5,642	6.72
Granted	975	6.18
Exercised	(562)	7.32
Expired	(237)	8.70
Forfeited	(569)	7.38
Outstanding, December 31, 2011	5,249	6.42
Granted	1,028	2.78
Exercised	–	–
Expired	(474)	6.14
Forfeited	(845)	6.51
Outstanding, December 31, 2012	4,958	5.68
Granted	2,587	2.16
Exercised	–	–
Expired	(1,120)	5.14
Forfeited	(531)	6.58
Outstanding, December 31, 2013	5,894	4.16
Exercisable, December 31, 2011	2,744	6.39
Exercisable, December 31, 2012	3,010	6.29
Exercisable, December 31, 2013	2,363	6.31

Shares authorized for issue under the option plan at December 31, 2013 were 11.5 million (December 31, 2012 – 8.0 million).

There were no stock options exercised in the twelve months ended December 31, 2013 (December 31, 2012 – nil).

The weighted average fair value of stock options granted from the stock option plan during the year ended December 31, 2013 was Cdn$1.45 (December 31, 2012 – Cdn$1.98, December 31, 2011 – Cdn$3.66) per option at the grant date using the Black-Scholes option pricing model. The weighted average assumptions used for the calculation were:

	2013	2012	2011
Expected life (in years)	6.2	6.3	6.4
Volatility (1)	76.9%	73.9%	74.0%
Dividend yield	–	–	–
Risk-free rate	1.6%	1.7%	2.2%
Estimated forfeiture rate	10.0%	8.1%	6.6%

(1) Expected volatility factor based on historical volatility of the Company's publicly traded common shares.

The following table summarizes information in respect of stock options outstanding and exercisable at December 31, 2013:

Range of Exercise Prices (Cdn$)	Outstanding (000s)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (Cdn$)
1.26 to 3.87	3,632	5.9	2.32
3.88 to 5.67	221	2.6	4.78
5.68 to 8.37	1,821	3.1	7.07
8.38 to 10.32	220	3.1	9.78
	5,894	4.8	4.16

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16.2 Restricted Share Unit Plan

The Company has a RSU plan under which it may issue restricted share units to eligible employees. RSUs vest in equal increments over three years and are settled in shares bought on the open market through a trust or cash on the anniversary date. RSUs do not entitle the holder to exercise voting rights until they have vested and the underlying shares have been delivered to the participant.

Details of transactions under the Company's RSU plan are as follows:

	Number of RSUs (000s) (1)	Weighted Average Fair Value (Cdn$)
Outstanding, December 31, 2010	–	–
Granted	372	4.86
Vested	–	–
Forfeited	(60)	6.24
Outstanding, December 31, 2011	312	4.59
Granted	849	2.04
Vested	(94)	3.42
Forfeited	(191)	3.03
Outstanding, December 31, 2012	876	2.16
Granted	1,693	0.72
Vested	(312)	2.07
Forfeited	(48)	1.94
Outstanding, December 31, 2013	2,209	1.01

(1) Includes RSUs that will be withheld on behalf of employees to satisfy statutory tax withholding requirements.

The weighted average fair value of RSUs granted during the year ended December 31, 2013 was Cdn$0.72 (December 31, 2012 was Cdn$2.04, December 31, 2011 – Cdn$4.86) per RSU at the grant date using the Black-Scholes option pricing model. The weighted average assumptions used for the calculation were:

	2013	2012	2011
Expected life (in years)	2.0	2.0	3.0
Volatility (1)	76.4%	69.2%	64.8%
Dividend yield	–	–	–
Risk-free rate	1.1%	1.1%	1.2%
Estimated forfeiture rate	18.8%	26.7%	6.1%

(1) Expected volatility factor based on historical volatility of the Company's publicly traded common shares.

The liabilities arising from the RSUs to be settled by way of cash payments and the intrinsic value of those liabilities are:

	December 31, 2013	December 31, 2012
Current liabilities related to RSUs	324	228
Long term liabilities related to RSUs	188	142

Intrinsic value of vested RSUs	–	–

17. RETIREMENT PLANS

In 2001, the Company adopted a defined contribution retirement or thrift plan (“401(k) Plan”) to assist US employees in providing for retirement or other future financial needs. Employees’ contributions (up to the maximum allowed by US tax laws) are matched 100% by the Company.

For the year ended December 31, 2013, the Company paid $0.2 million for retirement plan contributions (December 31, 2012 – $0.2 million, December 31, 2011 – $0.4 million).

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18. SEGMENT INFORMATION

Ivanhoe's organizational structure reflects its various operating activities and the geographic areas in which it operates. Oil and gas operations are divided into three geographic segments: Asia, Canada and Latin America.

Asian operations capture the Company's exploration in Mongolia. The Canadian segment comprises activities from Ivanhoe's oil sands development project at Tamarack. Latin America consists of exploration and development of Block 20 in Ecuador.

The Technology Development area captures costs incurred to develop, enhance and identify improvements in the application of the Company's HTL® technology. The Corporate area consists of costs that are not directly allocable to operating projects, such as executive officers, corporate financings and other general corporate activities.

The accounting policies of the segments are the same as the Company's consolidated accounting policies. Segment results include transactions between business segments. Corporate activities undertaken on behalf of a segment are allocated at cost. Segment liabilities include intercompany balances.

The following tables present the Company's segment income (loss), capital investments and identifiable assets and liabilities:

Year ended December 31, 2013	Asia	Canada	Latin America	Technology Development	Corporate(3)	Total
Interest and other income	–	3	–	299	125	427
Expenses and other						
Operating	–	–	–	4,426	–	4,426
General and administrative	690	2,549	7,096	4,559	23,174	38,068
Exploration and evaluation	15,381	–	–	–	–	15,381
Impairment of intangible assets	–	–	–	92,153	–	92,153
Impairment of property, plant and equipment	–	–	–	8,943	–	8,943
Depreciation	31	–	93	554	336	1,014
Foreign currency exchange (gain) loss	(4)	25	4	–	(3,681)	(3,656)
Derivative instruments loss	–	–	–	–	(177)	(177)
Finance	–	–	(72)	7	2,405	2,340
	16,098	2,574	7,121	110,642	22,057	158,492
Net loss before income taxes	(16,098)	(2,571)	(7,121)	(110,343)	(21,932)	(158,065)
Recovery (provision for) of income taxes						
Current	–	–	–	–	(41)	(41)
Deferred	2,717	–	–	33,092	(21,457)	14,352
	2,717	–	–	33,092	(21,498)	14,311
	(13,381)	(2,571)	(7,121)	(77,251)	(43,430)	(143,754)

Net loss and comprehensive loss from continuing operations						
Net loss and total comprehensive loss from discontinued operations	–	–	–	–	(2,072)	(2,072)
Net loss and comprehensive loss	(13,381)	(2,571)	(7,121)	(77,251)	(45,502)	(145,826)
Capital investments – Intangible	411	7,538	7,922	–	–	15,871
Capital investments – Property, plant and equipment	(50)	–	(80)	–	1,186	1,056

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Year ended December 31, 2012	Asia	Canada	Latin America	Technology Development	Corporate	Total
Interest and other income	–	3	–	–	25	28
Expenses and other						
Operating	–	–	–	4,252	–	4,252
General and administrative	1,689	3,821	5,336	3,184	17,119	31,149
Exploration and evaluation	2,968	159	19,867	–	–	22,994
Depreciation	45	1	164	567	184	961
Foreign currency exchange (gain) loss	(62)	–	–	–	1,309	1,247
Derivative instruments loss	–	–	–	–	(1,430)	(1,430)
Finance	–	18	(169)	5	4,474	4,328
Loss on debt repayment	–	–	–	–	2,977	2,977
	4,640	3,999	25,198	8,008	24,633	66,478
Net loss before income taxes	(4,640)	(3,996)	(25,198)	(8,008)	(24,608)	(66,450)
Recovery of income taxes						
Current	–	–	–	–	–	–
Deferred	–	–	–	36	2,396	2,432
	–	–	–	36	2,396	2,432
Net loss and comprehensive loss from continuing operations	(4,640)	(3,996)	(25,198)	(7,972)	(22,212)	(64,018)
Net income and total comprehensive income from discontinued operations	49,644	–	–	–	–	49,644
Net income (loss) and comprehensive income (loss)	45,004	(3,996)	(25,198)	(7,972)	(22,212)	(14,374)
Capital investments – Intangible	12,853	3,834	23,416	–	–	40,112
Capital investments – Property, plant and equipment	7,269	4	6	3	50	7,332

Year ended December 31, 2011	Asia	Canada	Latin America	Technology Development	Corporate	Total
Interest and other income	–	–	–	–	572	572
Expenses and other						
Operating	–	–	–	4,561	–	4,561
General and administrative	2,216	3,257	7,645	4,026	21,435	38,579
Exploration and evaluation	2,124	–	650	–	–	2,774
Depreciation	37	9	138	555	275	1,014
Foreign currency exchange (gain) loss	96	(6)	3	–	(627)	(534)

Derivative instruments gain	-	–	–	–	(13,148)	(13,148)
Finance	26	6	32	8	289	361
Gain on derecognition of long term provision	–	–	–	–	(1,900)	(1,900)
	4,499	3,266	8,468	9,150	6,324	31,707
Loss before income taxes	(4,499)	(3,266)	(8,468)	(9,150)	(5,752)	(31,135)
(Provision for) recovery of income taxes						
Current	–	–	–	–	(7)	(7)
Deferred	–	–	–	(1,389)	5,770	4,381
	–	–	–	(1,389)	5,763	4,374
Net income (loss) and comprehensive income (loss) from continuing operations	(4,499)	(3,266)	(8,468)	(10,539)	11	(26,761)
Net income and total comprehensive income from discontinued operations	1,485	–	–	–	–	1,485
Net income (loss) and comprehensive income (loss)	(3,014)	(3,266)	(8,468)	(10,539)	11	(25,276)
Capital investments – Intangible	20,390	6,280	10,720	–	–	37,390
Capital investments – Property, plant and equipment	12,733	–	43	879	15	13,670

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	Asia	Canada	Latin America	Technology Development	Corporate(3)	Total
As at December 31, 2013						
Assets(1)	125	153,682	92,342	87	(14,063)	232,173
Liabilities(2)	16,552	170,897	113,140	70,698	(299,391)	71,896
As at December 31, 2012						
Assets(1)	37,901	142,051	77,149	101,846	43,110	402,057
Liabilities(2)	25,616	156,696	97,325	95,205	(275,783)	99,059

(1) Segment assets include investments in subsidiaries that are eliminated for consolidation under the Corporate segment and assets classified as held for sale in the Asia segment as at December 31, 2012.
(2) Liabilities for the Corporate segment include intercompany receivables of $408.3 million at December 31, 2013 (December 31, 2012 – $367.0 million) required to eliminate intercompany payables upon consolidation.
(3) As at December 31, 2013, the Corporate segment includes the results of, and any remaining assets and liabilities of Sunwing Holding Corporation not related to the transfer of the participating interest in the Zitong Petroleum Contract to Shell China Exploration and Production Co. from Sunwing Zitong Energy, a wholly owned subsidiary of the Company.

19. CAPITAL MANAGEMENT

The Company defines capital as long term debt and total shareholders’ equity. At December 31, 2013, the Company is not subject to any financial covenants. The Company’s objectives are to safeguard Ivanhoe’s ability to continue as a going concern, to continue the exploration and development of its projects and to maintain a flexible capital structure which optimizes the costs of capital at an acceptable risk. To manage its capital requirements, the Company prepares an annual expenditure budget that is updated periodically. The annual and updated budgets are approved by the Board of Directors. Ivanhoe’s capital structure was as follows as at:

	December 31, 2013		December 31, 2012	
Long term debt	63,012	28.2 %	65,214	17.7 %
Shareholders’ equity	160,277	71.8 %	302,998	82.3 %
Total capital	223,289	100.0 %	368,212	100.0 %

The Company’s main source of funds has historically been public and private equity and debt markets. The Company does not anticipate cash flow from operating activities will be sufficient to meet its operating and capital obligations and, as such, the Company intends to finance its operating and capital projects from a combination of strategic investors in its projects and/or public and private debt and equity markets, either at a parent company level or at a project level.

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20. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash activities for the Company are comprised of the following:

Year ended December 31,	2013	2012	2011
Operating activities			
Accounts receivable	13,923	7,344	(2,210)
Prepaid and other	651	(235)	(301)
Note receivable	10	(3)	38
Accounts payable and accrued liabilities	(7,730)	1,575	5,306
Discontinued operations	–	908	–
	6,854	9,589	2,833
Investing activities			
Accounts receivable	–	(14,346)	716
Prepaid and other	(498)	53	1,748
Accounts payable and accrued liabilities	(687)	1,555	(10,779)
Discontinued operations	–	14,388	–
	(1,185)	1,650	(8,315)
Financing activities			
Accounts payable and accrued liabilities	(8)	(32)	57
	(8)	(32)	57
	5,661	11,207	(5,425)

21. RELATED PARTY TRANSACTIONS

Ivanhoe is party to cost sharing agreements with other companies which are related or controlled through common directors or shareholders. Through these agreements, the Company shares office space, furnishings, equipment, air travel and communications facilities in various international locations. Ivanhoe also shares the costs of employing administrative and non-executive management personnel at these offices. These related party transactions are in the normal course of business and the Company believes them to be valued at fair market value.

The breakdown of the related party expenses for the year ended December 31 is as follows:

Related Party	Nature of Transaction	2013	2012	2011
Global Mining Management Corp.	Administration	409	286	585
Ivanhoe Capital Aviation Ltd.	Aircraft	1,200	1,200	1,200
Ivanhoe Capital Services Ltd.	Administration	342	316	407
Ivanhoe Systems PTE Ltd.	Information technology	50	–	–
1092155 Ontario Inc.	HTL® technology	52	44	44
SouthGobi Resources Ltd.	Administration	–	44	154
Ensyn Technologies Inc.	HTL® technology	–	–	14
Ivanhoe Capital PTE Ltd.	Administration	–	–	150
Ivanhoe Capital Finance Ltd.	Financing	–	1,627	–
		2,053	3,517	2,554

The liabilities of the Company include the following amounts due to related parties:

Related Party	Nature of Transaction	December 31,	December 31,

		2013	2012
Global Mining Management Corp.	Administration	38	39
Ivanhoe Capital Services Ltd.	Administration	20	26
		58	65

In 2011, Ivanhoe sold Cdn$23.3 million of the Convertible Debentures, on a private placement basis and on the same terms as the public offering (Note 9.1), to certain officers and directors.

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22. REMUNERATION OF KEY MANAGEMENT PERSONNEL

The remuneration of directors and other key members of management was:

Year ended December 31,	2013	2012	2011
Base salaries or fees and other cash payments	6,067	4,416	3,762
Employer’s contributions to retirement plan	132	97	87
Share-based compensation expense	2,469	2,817	2,780
	8,668	7,330	6,629

23. INVESTMENTS IN SUBSIDIARIES

Ivanhoe has investments in the following 100% owned subsidiaries which principally affect the operating results or net assets of the Company. Subsidiaries which are inactive or immaterial have been omitted.

Name of Subsidiary	Jurisdiction of Incorporation or Formation
Ivanhoe Energy Canada Inc. *	Alberta
Ivanhoe Energy Holdings Inc. *	Nevada
Ivanhoe Energy Mongolia Inc. *	Alberta
PanAsian Energy Ltd.	Nevis
Shaman LLC	Mongolia
Ivanhoe Energy Latin America Inc. *	British Columbia
Ivanhoe Energy Ecuador Inc.	British Columbia
Ivanhoe HTL Petroleum Ltd.	Nevada

* - subsidiary held directly by Ivanhoe Energy Inc. All other companies are held through subsidiary undertakings.

24. SUBSEQUENT EVENT

In the first quarter of 2014, the Company decided to suspend activity its Tamarack Project, held in the Canada segment, pending regulatory clarity from the AER on the final guidelines for shallow SAGD projects. The Company does not expect the suspension to have an impact on the carrying value of the Tamarack assets; however, the carrying value of the capitalized costs will continue to be reviewed.

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SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES
(Unaudited)
(all tabular amounts are expressed in US$000s, except reserves and depletion rate amounts)

The following information about the Company's oil and gas producing activities is presented in accordance with Accounting Standards Codification 932 Extractive Activities – Oil and Gas (section 235-55) formerly US SFAS No. 69, "Disclosures About Oil and Gas Producing Activities".

Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company's share of reserves, excluding royalty interests of others. The reserves were based on the estimates by the independent petroleum engineering firm of GLJ Petroleum Consultants Ltd. The changes in the Company's net proved oil reserves in China for the three-year period ended December 31, 2013, were as follows:

(mbbls)	Developed	Undeveloped	Total(1)
Net proved reserves, December 31, 2010	1,265	473	1,738
Revisions of previous estimates	271	(171)	100
Extensions and discoveries	52	98	150
Production	(353)	–	(353)
Net proved reserves, December 31, 2011	1235	400	1,635
Production	(284)	–	(284)
Sale of reserves in place	(951)	(400)	(1,351)
Net proved reserves, December 31, 2012	–	–	–
Net proved reserves, December 31, 2013	–	–	–

(1) None of the Company's proved oil reserves are related to bitumen.

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Net proved producing reserves in China as at December 31, were as follows:

(mbbls)	
2011	1,235
2012	–
2013	–

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

For the years ended December 31, 2013, 2012, and 2011 future net cash flows were computed using 12 month historical average prices in estimating the Company's proved oil reserves, current costs, and statutory tax rates adjusted for tax deductions, that relate to existing proved oil reserves. The following standardized measure of discounted future net cash flows from proved oil reserves was computed using prices of $93.91 bbl of oil for 2011. The standardized measure of discounted future net cash flows from proved oil reserves was nil for 2013 and 2012 as the Company disposed of all of is proved reserves as part of the sale of Pan-China Resources Ltd. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

— future production from proved reserves will differ from estimated production;

— future production may also include production from probable and possible reserves;

— future, rather than average annual, prices and costs will apply; and

— existing economic, operating and regulatory conditions are subject to change.

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The standardized measure of discounted future net cash flows for China as at December 31 in each of the three most recently completed financial years were as follows:

	2013(1)
Future cash inflows	–
Future development and restoration costs	–
Future production costs	–
Future income taxes	–
Future net cash flows	–
10% annual discount	–
Standardized measure	–

(1) The Company disposed of all of its proved reserves as part of the sale of Pan-China Resources Ltd., any revenue generated in 2012 from proved reserves is accounted for in discontinued operations.

	2012(1)
Future cash inflows	–
Future development and restoration costs	–
Future production costs	–
Future income taxes	–
Future net cash flows	–
10% annual discount	–
Standardized measure	–

(2) The Company disposed of all of its proved reserves as part of the sale of Pan-China Resources Ltd., any revenue generated in 2012 from proved reserves is accounted for in discontinued operations.

	2011
Future cash inflows	178,378
Future development and restoration costs	(12,260)
Future production costs	(75,639)
Future income taxes	(14,656)
Future net cash flows	75,823
10% annual discount	(20,713)
Standardized measure	55,110

Note: The Company is using current costs in the preparation of the information shown in the tables above and to determine proved reserves. However, future production costs may not be easily comparable to historical production costs. The two main causes of difficulty in analyzing future production costs when compared to historical spending are summarized as follows:

1. In March 2006, the Ministry of Finance of the Peoples Republic of China ("PRC") issued the "Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business" (the "Windfall Levy Measures"). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling oil in the PRC are subject to a windfall gain levy (the "Windfall Levy") if the monthly weighted average price of oil is above $40.00/bbl. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40.00/bbl. As a result, the cost associated with the Windfall Levy is not related to production volumes but instead is related to the commodity price. As an example, as oil prices increased during 2008, the amount of the Windfall Levy also increased significantly, resulting in a $13.46 per bbl increase in 2008 when compared to 2007. The Windfall Levy accounted for $21.14/bbl cost of the total $43.92/bbl operating costs in our China operations, or in absolute terms $10.4 million of the total $21.5 million. This compared to only

$4.00/bbl or $1.9 million in absolute terms incurred during 2009. On November 1, 2011, China's Ministry of Finance raised the windfall levy threshold from $40.00/bbl to $55.00/bbl.

2. Effective January 1, 2009, the Dagang field reached "Commercial Production" status as defined by the Production Sharing Contract with our partner CNPC. The effect of this change is that the Company no longer pays 100% of operating costs but now pays 82%, representing the "pre-cost recovery" proportionate share. Effective September 1, 2009, the project reached cost recovery and the working interests changed to 51% CNPC and 49% for the Company. In our 2008 independent reserve report that was used to prepare the standardized measure disclosures above, the 49/51% reversion was estimated based on total costs yet to recover.

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Changes in standardized measure of discounted future net cash flows from China as at December 31 in each of the three most recently completed financial years were as follows:

	2013
Sale of oil and gas, net of production costs	–
Net changes in prices and production costs	–
Extensions and discoveries, net of future production and development costs	–
Net change in future development costs	–
Development costs incurred during the period that reduced future development costs	–
Revisions of previous quantity estimates	–
Accretion of discount	–
Net change in income taxes	–
Sale of reserves in place	–
Changes in production rates (timing) and other	–
Decrease	–
Standardized measure, beginning of year	–
Standardized measure, end of year	–

	2012
Sale of oil and gas, net of production costs	(17,771)
Net changes in prices and production costs	–
Extensions and discoveries, net of future production and development costs	–
Net change in future development costs	–
Development costs incurred during the period that reduced future development costs	–
Revisions of previous quantity estimates	–
Accretion of discount	–
Net change in income taxes	–
Sale of reserves in place	(37,339)
Changes in production rates (timing) and other	–
Decrease	(55,110)
Standardized measure, beginning of year	55,110
Standardized measure, end of year	–

	2011
Sale of oil and gas, net of production costs	(21,833)
Net changes in prices and production costs	24,927
Extensions and discoveries, net of future production and development costs	9,426
Net change in future development costs	(18,571)
Development costs incurred during the period that reduced future development costs	12,605
Revisions of previous quantity estimates	4,485
Accretion of discount	3,965
Net change in income taxes	(2,418)
Changes in production rates (timing) and other	2,877
Increase	15,463
Standardized measure, beginning of year	39,647
Standardized measure, end of year	55,110

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Costs incurred in oil and gas property acquisition, exploration, and development activities for the Company's oil and gas properties for the years ended December 31 were as follows:

	2013	2012	2011
Canada			
Exploration	11,196	8,176	9,697
	11,196	8,176	9,697
Ecuador			
Property acquisition			
Unproved	–	–	767
Exploration	7,982	25,560	11,536
	7,982	25,560	12,303
Asia(1)			
Exploration	722	12,453	23,094
Development	–	7,878	12,923
	722	20,331	36,017
Total	19,900	54,067	58,017

(1) The Company disposed of all of its proved reserves as part of the sale of Pan-China Resources Ltd., costs incurred at Pan-China Resources Ltd. during 2012 and 2011 are included in exploration and development costs.

The depletion rates, on a net production basis, were as follows:

China ($/bbl)	
2013	–
2012	22.63
2011	19.54

The results of operations from producing activities for the years ended December 31 were as follows:

	2013	2012	2011
Oil revenue	–	32,466	37,403
Operating	–	(12,186)	(15,570)
Depletion	–	(6,681)	(7,053)
Results of operations from producing activities	–	13,599	14,780

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ITEM 9: CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A: CONTROLS AND PROCEDURES

The Company's management, including our Executive Chairman and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2013. Based upon this evaluation, management concluded that these disclosure controls and procedures were effective to ensure that (1) information required to be disclosed in the Company's reports under the Exchange Act is accumulated and communicated to the Company's Executive Chairman and Chief Financial Officer to allow timely decisions regarding required disclosure and (2) information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

—pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

—provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with Canadian generally accepted accounting principles applicable to publicly accountable enterprises, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

—provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (1992). Based on our assessment, management has concluded that, as of December 31, 2013, the Company's internal control over financial reporting was effective based on those criteria. Management has reviewed the results of its assessment with the Audit Committee of the Board of Directors. Deloitte LLP, the Company's Independent Registered Public Accounting Firm that audited the consolidated financial statements included in Item 8 of this Form 10-K, has also audited the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, as stated in their report which immediately follows.

/s/ Carlos A. Cabrera	/s/ Gerald D. Schiefelbein
Carlos A. Cabrera	Gerald D. Schiefelbein
Executive Chairman	Chief Financial Officer

March 17, 2014

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REPORT OF INDEPENDENT PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Ivanhoe Energy Inc.

We have audited the internal control over financial reporting of Ivanhoe Energy Inc. and subsidiaries (the "Company") as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Accounting Standards as issued by the International Accounting Standards Board, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated March 17, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ Deloitte LLP
Chartered Accountants

March 17, 2014
Calgary, Canada

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CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company's internal control over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B: OTHER INFORMATION

Not applicable.

PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Each director is elected for a one-year term or until his successor has been duly elected or appointed. All of our directors were elected at our last annual general meeting of shareholders ("AGM") held on April 22, 2013. The term of office of each director concludes at our next AGM, unless the director's office is earlier vacated in accordance with our by-laws.

Name	Age	Positions Held	Ivanhoe Director Since
Carlos A. Cabrera	62	Executive Chairman	2010
Robert M. Friedland	63	Founder and Executive Co-Chairman	1995
A. Robert Abboud	84	Independent Lead Director	2006
Howard R. Balloch	62	Director	2002
Brian F. Downey	72	Director	2005
Robert G. Graham	60	Director	2005
Peter G. Meredith	70	Director	2007
Alexander A. Molyneux	39	Director	2010
Robert A. Pirraglia	64	Director	2005

Officers serve at the pleasure of the Board of Directors.

Name	Age	Current Position	Executive Officer Since
Carlos A. Cabrera	62	Executive Chairman	2011
Robert M. Friedland	63	Founder and Executive Co-Chairman	2008
Gerald D. Schiefelbein	55	Senior Vice President, Finance and Chief Financial Officer	2009
Greg G. Phaneuf	44	Senior Vice President, Business Development & Corporate Strategy	2010
Michael A. Silverman	60	Senior Vice President, Downstream Technology and Chief Technology Officer	2007
Edwin J. Veith	55	Senior Vice President, Canadian Projects	2007
Joseph D. Kuhach	52	Senior Vice President, Upstream Technology & Integration	2008
Marlene A. Duff	63	Senior Vice President, Human Resources	2008

William E. Parry	63	Senior Vice President & General Counsel	2013
Santiago Pàstor Morris	55	Senior Vice President & General Manager Ecuador	2012

A. ROBERT ABBOUD

Mr. Abboud has been the Independent Lead Director of the Company since May 2006 and serves as an ex-officio member of the Company's Audit, Nominating and Corporate Governance and Compensation and Human Resources Committees. He is also a member of the Executive Committee. He was Co-Chairman of the Company from May 2006 to December 2011. Mr. Abboud has been President and Chief Executive Officer of A. Robert Abboud and Company, a private investment company, since 1984, and has had a 46-year career in oil and gas, banking and foreign affairs. He was previously President and Chief Operating Officer of Occidental Petroleum Corporation, Chairman and Chief Executive Officer of First Chicago Corporation and The First National Bank of Chicago, Chairman and Chief Executive Officer of First City Bancorporation of Texas, Chairman of ACB International, Ltd., a joint venture that included the Bank of China and a subsidiary of the Chinese Ministry of Foreign Relations and Trade. Mr. Abboud has served as a member of the Board of Directors of AMOCO and as a Board and Compensation Committee member as well as Audit Committee Chairman for AAR Corporation, Alberto-Culver Company, Hartmarx Corporation, ICN Pharmaceuticals Inc. and Inland Steel Industries. Mr. Abboud holds a Bachelor of Arts (Cum Laude) from Harvard College, a J.D. from Harvard Law School and a Master of Business Administration from

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Harvard Business School, and is a member of the Illinois and Massachusetts Bar Associations, as well as the Federal Bar and American Bar Associations. Mr. Abboud was selected to serve on our Board due to his extensive experience at the senior executive and board level in the oil and gas industry and in international finance, and for the financial acumen, strategic insight, acute business judgment and international business experience he brings to the Company.

ROBERT M. FRIEDLAND

Mr. Friedland has been Founder and Executive Co-Chairman of the Company since May 2008. A co-founder of the Company, Mr. Friedland has been a director since February 1995. He was formerly Deputy Chairman from June 1999 to May 2008, President from May 2008 to May 2010 and Chief Executive Officer from May 2008 to December 2011. Mr. Friedland has served on the Company's Executive Committee since its formation in October 2008 and was Chair of the Executive Committee from October 2008 to December 2011.

Mr. Friedland brings many valuable attributes to the Ivanhoe Energy Board, including his extensive experience in international corporate finance and as a senior executive and director of several internationally-focused, natural resource companies and his proven track record in overseeing the discoveries of major mineral deposits in Canada, Mongolia, Africa and elsewhere.

Mr. Friedland founded Ivanhoe Mines Ltd. (now Turquoise Hill Resources Ltd.) and was Executive Chairman from March 1994 to April 2012 and Chief Executive Officer from October 2010 to April 2012. He also is the founder of Ivanplats Limited (now Ivanhoe Mines Ltd. ("Ivanhoe Mines")), a public company presently advancing mineral projects in Africa and the Democratic Republic of Congo, and has been Ivanhoe Mines' Executive Chairman since November 2000 and was President from June 2003 to May 2008.

Mr. Friedland founded Ivanhoe Capital Corporation and has been its Chairman since 1991 and President since 1988. Ivanhoe Capital is a private, Singapore-based company specializing in providing venture capital and project financing for international business enterprises, predominantly in the fields of energy and minerals. He was Chairman of Potash One Inc., a Canadian public company, from May 2009 to January 2011.

HOWARD R. BALLOCH

Mr. Balloch has been a director of the Company since January 2002. Mr. Balloch chairs the Compensation and Human Resources Committee, and is a member of the Nominating and Corporate Governance and Executive Committees. From January 2011 until March 2013, he served as Chairman of Canaccord Genuity Asia Limited, the Asian subsidiary of Canaccord Financial Inc. which acquired in 2011 The Balloch Group, an investment advisory firm Mr. Balloch founded in 2001. A veteran Canadian diplomat, Mr. Balloch served as Canada's ambassador to the People's Republic of China, Mongolia and the Democratic People's Republic of Korea between 1996 and 2001, at the end of a 25-year career in the Government of Canada's Department of Foreign Affairs and International Trade and the Privy Council Office. Mr. Balloch is Vice Chairman of the Canada China Business Council, having served as its President between 2001 and 2006. Mr. Balloch holds a Bachelor of Arts (Honours) degree in Political Science and Economics and a Master of Arts in International Relations from McGill University, after which he pursued further studies at the University of Toronto and at Fondation Nationale de Sciences Politiques in Paris. Mr. Balloch was selected to serve as a director on our Board based on his experience as a Canadian diplomat and as an international businessman, his extensive knowledge of foreign affairs and the political and regulatory environment in many of the key regions in which the Company operates and his knowledge and experience in matters of public company governance.

CARLOS A. CABRERA

Mr. Cabrera has been a director of the Company since May 2010 and was appointed as Executive Chairman of the Company in December 2011. Mr. Cabrera serves as the Chair of the Executive Committee and served as a member of the Audit, Nominating and Corporate Governance and Compensation and Human Resources Committees from May 2010 to December 2011. Mr. Cabrera is the former Chairman (January 2009 to July 2009), President and Chief Executive Officer (from December 2006 to January 2009) of UOP LLC, a Honeywell company. During his 35 year career with UOP, he held several managerial and technology positions, including Senior Vice President of Refining and Petrochemicals, Senior Vice President of Process Technology and Equipment and Vice President of Corporate Development and New Ventures. Mr. Cabrera served as the President and Chief Executive Officer of the National Institute of Low Carbon and Clean Energy (NICE), a wholly owned subsidiary of the Shenhua Group, based in Beijing, China, from December 2009 to November 2011. Since June 2010, Mr. Cabrera has also served as a director of GEVO, Inc., a publicly traded biotechnology company, and is a member of its Nominating and Corporate Governance and Audit Committees. In January 2012, he joined the Board of Directors of the Gas Technology Institute, a US based research institute, development and training organization serving energy and environmental markets. Mr. Cabrera has been a member of the Executive Board of Big West Oil LLC, a private

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US oil company, since December 2011. Mr. Cabrera also serves as a Distinguished Associate to the World Energy Consultancy Firm FACTS. Mr. Cabrera serves on the Global Advisory Board of the University of Chicago's Booth School of Business. During Mr. Cabrera's 36 years in the refining and petrochemicals industry, he has been granted seven U.S. patents, authored numerous publications and frequently serves on industry panels as a recognized business and technical leader. He has a Bachelor of Science degree in chemical engineering from the University of Kentucky and a Master's degree in business administration from the University of Chicago. Mr. Cabrera brings to the Board extensive experience in petroleum refining, gas processing and petrochemical production as well as international business development and senior executive management experience.

BRIAN F. DOWNEY

Mr. Downey joined the Board of Directors and was appointed Chairman of the Audit Committee in July 2005. Mr. Downey also serves as a member of the Compensation and Human Resources Committee. He served as a member of the Nominating and Corporate Governance Committee from April 2009 until April 2013. Mr. Downey has been President of Downey & Associates Management Inc., a real estate holding company, since July 1986, and Financial Advisor to Lending Solutions, Inc., a full-service loan call centre located in the US whose clients are primarily US and Canadian financial institutions, since January 2002. From 1995 to 2002 he was a principal and served as Chief Executive Officer ("CEO") of Lending Solutions, Inc., and from 1986 to 1995 he served as President and Chief Executive Officer of Credit Union Central of Canada, the national trade association and national liquidity facility for all credit unions in Canada. Mr. Downey has a Certified Management Accountant (CMA) designation acquired through the University of Manitoba and is a Member of the Society of Management Accountants of Ontario. Mr. Downey was selected to serve as a director on our Board due to his extensive experience and expertise in financial and accounting matters. Mr. Downey is the Company's "audit committee financial expert" within the meaning of the Securities Exchange Act of 1934, as amended.

DR. ROBERT G. GRAHAM

Dr. Graham has been a director of the Company since April 2005 and served as the Company's Chief Technology Officer from April 2007 to September 2007. Dr. Graham co-founded Ensyn and served on the board and in various senior executive roles with Ensyn and its predecessor companies since 1984 until it was acquired by the Company in 2005. Since then, he has served as Chairman (since June 2007) and Chief Executive Officer (since July 2008), and President and Chief Executive Officer (from April 2005 to June 2007) of Ensyn Corporation. Dr. Graham has been working on the commercial development of the RTP™ biomass refining and petroleum upgrading technologies since the early 1980s. This work culminated in the development of commercial RTP™ applications in the wood industry in the late 1980's and the establishment of Ensyn Renewables Inc. to capitalize on commercial projects for this business. In 1997, Dr. Graham initiated the application of this commercial RTP™ technology in the petroleum industry. Dr. Graham holds Bachelor of Science and Bachelor of Science Honours degrees from Carlton University, and a Master of Engineering and Ph.D. in Chemical Engineering from the University of Western Ontario. Dr. Graham brings unique skill, expertise and experience to our Board as the inventor of our HTL® technology and as a scientist and businessman with extensive experience in the technology industry.

PETER G. MEREDITH

Mr. Meredith joined the Board of Directors in December 2007 and serves as a member of the Executive Committee. He previously served as a director from 1996 to 1999 and as the Company's Chief Financial Officer from June 1999 to January 2000. Mr. Meredith was the Deputy Chairman of Ivanhoe Mines Ltd. (now Turquoise Hill Resources Ltd.), from May 2006 to April 2012 and was Chief Financial Officer of Ivanhoe Mines Ltd. from May 2004 to May 2006 and from June 1999 to November 2001. He also was the Chairman of SouthGobi Resources Ltd. from October 2009 to September 2012 and was previously Chief Executive Officer from June 2007 to October 2009.

Mr. Meredith served as Chief Financial Officer of Ivanhoe Capital Corporation from June 2001 to March 2009. Prior to joining the Company, Mr. Meredith spent 31 years with Deloitte & Touche LLP, Chartered Accountants, where he retired as a partner in 1996. He was a member of its Canadian board of directors from 1991 to 1996. Mr. Meredith is a Chartered Accountant and is a member of the Institute of Chartered Accountants of British Columbia, the Institute of Chartered Accountants of Ontario and the Ordre des Comptables Agrees du Quebec. Mr. Meredith was selected to serve as a director on our Board due to his extensive experience at the senior executive and board level with international resource companies and his financial accounting, reporting and corporate finance expertise, and the depth of his knowledge of the Company's operations and of the political and regulatory requirements of the regions in which the Company operates derived from his involvement in leadership roles with the Company and other resource companies operating in similar regions since 1996.

ALEXANDER A. MOLYNEUX

Mr. Molyneux has been a director of the Company since May 2010. Mr. Molyneux has been the Executive Chairman of Celsius Coal Limited (ASX:CLA) since December 2012 and the Chairman designate of Blumont Group Ltd. (SIN:BLUM) since October

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2013. He has also served as a non-executive director of Goldrock Mines Corp. (TSX:GRM), a mining development and exploration company, since December 2012. Mr. Molyneux was the President (April 2009 to September 2012), Chief Executive Officer (October 2009 to September 2012) and a director (October 2009 to September 2012) of SouthGobi Resources Ltd. (TSX:SGQ, HK:1878). Mr. Molyneux was Head of Metals and Mining Investment Banking for Citigroup where he established a leading metals and mining investment banking business in Asia. During his career at Citigroup and UBS, he advised on natural resources industry public offerings, mergers and acquisitions, bond and debt offerings totaling several billion dollars. Mr. Molyneux holds a Bachelor’s degree in Economics from Monash University in Australia. Mr. Molyneux was selected to serve as a director on our Board based on his comprehensive background in the areas of international capital markets, corporate finance and investment banking in Asia and elsewhere and his experience in doing business in the natural resource sector in China and Mongolia.

ROBERT A. PIRRAGLIA

Mr. Pirraglia has been a director of the Company since April 2005 and acted as the Chair of the Business Development Committee from August 2007 until May 2008. He is currently the Chair of the Nominating and the Corporate Governance Committee and a member of the Audit Committee. Mr. Pirraglia is an engineer and attorney with more than 30 years of experience in the development of energy projects and projects employing innovative technologies. He served on the board of Ensyn Group, Inc. starting in 1996, and was also Chief Operating Officer of Ensyn Group, Inc. from September 1998 to April 2005. He has been a member of the board of Ensyn Corporation since June 2005 and was its Chief Operating Officer and Vice President from April 2005 to October 2007 and its Executive Vice President from October 2007 to June 2011. Since June 2011, he has served as President of Ensyn Corporation. Mr. Pirraglia has been a member of the Management Committee of Envergent Technologies LLC, a Honeywell Company, that is a joint venture between Ensyn Corporation and UOP, LLC since October 2007 and a member of the board of F&E Technologies, LLC, a joint venture between Ensyn Corporation and Fibria Celulose, S.A. In addition to being a founder and manager of several energy and waste processing companies, Mr. Pirraglia has provided management and business consulting services to various US, Canadian and European companies. Mr. Pirraglia holds a Bachelor of Engineering in Electrical Engineering degree from New York University and a J.D. from Fordham University School of Law. Mr. Pirraglia brings significant legal, technical and project management experience and expertise to our Board as well as governance experience from acting as a public company director.

GERALD D. SCHIEFELBEIN

Mr. Schiefelbein has been the Chief Financial Officer of the Company since November 2009 and Senior Vice President, Finance since September 2012. He brings 26 years of finance experience in the international oil and gas industry, having worked in North America, Europe and the Middle East with the BP Group and Amoco. Immediately prior to joining the Company, Mr. Schiefelbein was Chief Financial Officer with Chicago-based BP plc, Integrated Supply & Trading from September 2007 to February 2009, where he led the finance department for BP's crude and oil-products supply and trading operations in the Americas. Prior to his appointment as Chief Financial Officer of BP plc, Integrated Supply & Trading, Mr. Schiefelbein served as Controller from February 2006 to September 2007.

Mr. Schiefelbein has substantial finance and control experience throughout the exploration and production value chain, including exploration bidding, production operations, gas plants, pipelines and supply and trading operations. In addition, he is highly experienced with merging companies and operations.

GREG G. PHANEUF

Mr. Phaneuf was appointed Senior Vice President, Business Development and Corporate Strategy in September 2012. He previously served as Executive Vice President, Corporate Development of the Company from March 2011 to September 2012 and as Senior Vice President, Corporate Development from September 2010 to March 2011. Mr.

Phaneuf is responsible for the overall approach and execution on the Company's existing corporate development projects, as well pursuing new corporate development initiatives. He also leads the Investor Relations and Communications Department and is a key spokesperson in dealing with the investment community.

Mr. Phaneuf has 22 years of related experience which includes Vice President, Corporate Development, for The Churchill Corporation from September 2009 to September 2010, where he led a $390 million corporate acquisition, as well as leading the associated $200 million equity and convertible debenture financing and a new $200 million revolving credit facility.

Prior to joining Churchill, Mr. Phaneuf was Vice President and Chief Financial Officer of Seven Generations Energy, a private energy resource and development company, and from September 2004 to October 2007, he was the Treasurer for Western Oil Sands Inc., where he actively participated in that company's financings, M&A activities and risk management functions. Mr. Phaneuf was an integral member of the deal team associated with Western Oil Sands $7 billion divestiture to Marathon Corporation in 2007.

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MICHAEL A. SILVERMAN

Dr. Silverman was appointed Senior Vice President, Downstream Technology in September 2012 and has served as the Chief Technology Officer of the Company since September 2007. He previously served as the Executive Vice President, Technology from September 2007 to September 2012. From May, 2007 to September, 2007 he was Vice President, Technology. Since joining the Company in 2007, Dr. Silverman has been responsible for all technical aspects of the Company's proprietary HTL® upgrading process. This includes interfacing with leading engineering firms in the design of commercial HTL® installations, technology development and intellectual property management.

Dr. Silverman has almost 30 years of experience in technology development and management, including the commercialization and marketing of new technologies, and is a leading expert in the fluid catalytic cracking (FCC) processes. Dr. Silverman served as Vice President, Petrochemicals (May 2004 to May 2007) and Director, Technology Center (May 2000 to May 2004) for Kellogg, Brown and Root, now KBR, Inc.

Prior to joining KBR, Dr. Silverman was the Manager of Technology Development for Stone & Webster, Inc. where he managed all aspects of technology development in the refining business, including FCC's and several heavy oil upgrading technologies. Earlier experience included the management of fluid catalytic cracking for Tenneco Oil Company, and an assistant professorship in Chemistry at Rutgers University.

EDWIN J. VEITH

Mr. Veith has been the Senior Vice President, Canadian Projects since September 2012. He previously served as Executive Vice President, Upstream from September 2007 to September 2012. Mr. Veith has also been Vice President, HTL® Technology of Ivanhoe Energy (USA) Inc. from November 2005 until June 2009.

Mr. Veith has over 31 years of experience in the oil industry with a focus on heavy oil recovery techniques. Mr. Veith joined the Company in 2001 from Aera Energy, a California joint venture of Shell and ExxonMobil, where he had responsibility for heavy oil development and operations in the giant Belridge and Cymric heavy oil fields in California. He managed thermal horizontal and vertical well development projects using state of the art reservoir management techniques and utilized advanced 3-D reservoir visualization methods to integrate complex data sets. He planned new project expansions and investigated new development scenarios using reservoir simulation and advanced economic modeling. Mr. Veith previously worked with Insight Energy, LLC, Bechtel and Williams Brothers. As President of Insight Energy, LLC, Mr. Veith evaluated major oil fields for acquisition and joint ventures.

JOSEPH D. KUHACH

Mr. Kuhach was appointed Senior Vice President, Upstream Technology and Integration in September 2012. Mr. Kuhach is responsible for global upstream technology and for providing strategic leadership in assessing and developing the Company's assets. He has 27 years of energy industry experience focused predominantly on heavy oil recovery and upgrading. Mr. Kuhach was the Vice President, Engineering, Upstream and Integration with the Company from August 2008 to September 2012. Prior to joining the Company in 2005, Mr. Kuhach spent 20 years with Shell and its subsidiaries in engineering and management positions. As Manager of Technology he oversaw heavy oil recovery efforts for Shell's largest thermal assets including Belridge, Cymric, McKittrick, and Lost Hills fields. During his time with Shell, Mr. Kuhach was a leader in advancing horizontal well implementation in thermal recovery applications. He led the effort to design and implement Shell's first grass roots thermal horizontal well project. Mr. Kuhach has published numerous papers and is a past technical editor for Society of Petroleum Engineering (SPE) Reservoir Evaluation and Engineering magazine.

MARLENE A. DUFF

Ms. Duff has been Senior Vice President, Human Resources since September 2012. Previously, Ms. Duff was the Vice President, Human Resources from October 2008 to September 2012. Ms. Duff is responsible for company-wide human resource strategy, staffing, compensation & benefits, organizational design, talent management and human resource administrative services on behalf of the Company.

Prior to joining Ivanhoe in 2008, Ms. Duff held human resource management positions in oilfield services, banking, chemicals and E&P in both domestic and international organizations. With over 30 years of experience, Ms. Duff has been responsible for human resource strategies focused on best practice cultures and work environments and large scale redesign of HR programs in performance management, resource planning, leadership development and business process improvement.

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WILLIAM E. PARRY

Mr. Parry joined the Company as Senior Vice President and General Counsel in April 2013 and is responsible for all legal activities for the company.

He brings a wealth of experience having managed the legal affairs of several chemical and energy companies in North America and internationally. Specifically, Mr. Parry has extensive commercial legal experience with acquisitions and divestitures, technology transfer, and managing patent programs, as well as experience leading a law department. He was Vice President and General Counsel at Nalco Chemical Company from 1995-2001, Assistant General Counsel at UOP from 1988-1993, and has business experience as Director of Business Development and Planning for UOP's catalyst and adsorbent business and as President of Nalco Industrial Outsourcing from 1993-1995. Bill also acted as a legal consultant for the National Institute for Clean and Low Carbon Energy in Beijing.

Mr. Parry received a chemical engineering degree from the University of Notre Dame and a J.D. from Duquesne University's School of Law. He is licensed to practice law in Illinois, Pennsylvania, and before the U.S. Patent and Trademark Office.

SANTIAGO PÁSTOR MORRIS

Mr. Pástor Morris has served as Senior Vice President of the Company and President and General Manager of the Company's wholly owned subsidiary, Ivanhoe Energy Ecuador Inc., since September 2012. Previously, he served as Vice President, Operations of Ivanhoe Energy Ecuador from May 2010 to September 2012.

Mr. Pástor Morris was Operations Manager for Petrobras Energia Ecuador from January 2005 until May 2010. He has over 25 years of experience in upstream design, construction, and operations in the international oil and gas industry. His expertise has taken him beyond Latin America to the USA and Europe, working with companies like Texaco, Petroecuador, Oryx Energy Company, Kerr McGee Ecuador Energy Corporation, Perenco Energy Ecuador, and Petrobras Energia Ecuador.

OTHER PUBLIC COMPANY DIRECTORSHIPS

The following table sets out information respecting directorships held by our directors over the last five years at public and registered investment companies:

Director	Company	Date
Robert Friedland	Ivanhoe Mines Ltd. (formerly Ivanplats Limited)	Nov 2000 - present
	Ivanhoe Mines Ltd. (now Turquoise Hill Resources Ltd.)	March 1994 – April 2012
	Potash One Inc.	May 2009 – Jan 2011
	Ivanhoe Australia Ltd. (now Inova Resources Limited)	Nov 2007 – Apr 2012
Carlos A. Cabrera	GEVO, Inc.	Jun 2010 - present
Howard Balloch	Methanex Corporation	Apr – 2004 - present
	Ivanhoe Mines Ltd. (now Turquoise Hill Resources Ltd.)	Mar 2005 – Jul 2011
	Canaccord Financial Inc.	Jan 2011 – Jun 2011
	Tiens Biotech Group USA Inc.	May 2006 – Mar 2010
Peter Meredith	Ivanhoe Mines Ltd. (formerly Ivanplats Limited)	May 1998 - present
	Great Canadian Gaming Corporation	Jun 2000 - present

	Peregrine Diamonds Ltd.	Mar 2013 - present
	Trevali Mining Corporation	Jul 2013 - present
	Kaizen Discovery Inc.	Dec 2013 – present
	Entrée Gold Inc.	Nov 2004 – Jul 2013
	Turquoise Hill Resources Ltd. (formerly Ivanhoe Mines Ltd.)	Mar 2005 - May 2013
	SouthGobi Resources Ltd.	Aug 2003 - Sept 2012
	Ivanhoe Australia Ltd (now Inova Resources Limited)	Nov 2006 – Apr 2012
Alexander Molyneux	Blumont Mining Group	Oct 2013 - present
	Celsius Coal Limited	Dec 2012 - present
	Goldrock Mines Corp.	Dec 2012 - present
	SouthGobi Resources Ltd.	Oct 2009 - Sep 2012

BOARD COMMITTEES

As required under the Business Corporations Act (Yukon) and under section 3(a)(58)(A) of the Exchange Act, our Board of Directors has a separately designated standing Audit Committee. The members of the Audit Committee are Messrs. Brian F. Downey (Chair), Alex A. Molyneux and Robert A. Pirraglia. Mr. Downey, one of our current independent directors, has been determined by the Board of Directors to be an Audit Committee financial expert. We believe that Mr. Downey's prior experience working as a Certified Management Accountant and significant financial and business experience at the executive levels of management qualifies him to be an Audit Committee financial expert.

We also have a Compensation and Human Resources Committee, a Nominating and Corporate Governance Committee and an Executive Committee. The current members of the Compensation and Human Resources Committee are Messrs. Howard R. Balloch (Chair), Brian F. Downey and Robert G. Graham. The current members of the Nominating and Corporate Governance Committee are Messrs. Robert A. Pirraglia (Chair), Alex A. Molyneux and Howard R. Balloch.

Mr. A. Robert Abboud, the Independent Lead Director, is an ex-officio member of each of the Audit, Nominating and Corporate Governance, and Compensation and Human Resources Committees.

The current members of the Executive Committee are Messrs. Carlos A. Cabrera (Chair), Robert M. Friedland, A. Robert Abboud, Howard R. Balloch, and Peter G. Meredith.

CODE OF BUSINESS CONDUCT AND ETHICS

We have a Code of Business Conduct and Ethics applicable to all employees, consultants, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code of Business Conduct and Ethics provides that our employees, consultants, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, consultants, officers and directors. The Code of Business Conduct and Ethics was amended in November 2007 to reflect our adoption of a whistleblower policy and to update our internal reporting process in connection with Code-related matters.

A copy of our Code of Business Conduct and Ethics, as amended, may be obtained, without charge, by request to Ivanhoe Energy Inc., Suite 654-999 Canada Place, Vancouver, British Columbia, Canada V6C 3E1, Attention: Corporate Secretary or by phone to 604-688-8323.

ITEM 11: EXECUTIVE COMPENSATION

We are a foreign private issuer that voluntarily files its annual reports on Form 10-K. As permitted by Item 402(a)(1) of Regulation S-K, we follow the disclosure requirements applicable in Canada with respect to executive compensation (Form 51-102 F6 of the CSA), which we believe address the requirements of, and require more detailed information than, Items 6.B and 6.E.2 of Form 20-F.

COMPENSATION DISCUSSION AND ANALYSIS

Executive Summary

— The purpose of the Company's compensation program for senior executives is to provide incentives to attract, motivate and retain qualified and experienced executives, to ensure their interests are aligned with shareholders and to provide fair transparent and defensible compensation.

— The Board, through its Compensation and Human Resources Committee (the "Compensation Committee") is committed to the transparent presentation of its compensation program.

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The three principal elements that make up the compensation program are: base salary, performance bonus and long term incentives.

— Salary for senior executives is targeted at the median of the market while overall compensation, inclusive of salary, performance incentive bonus and long term incentives is targeted at the seventy-fifth percentile of the market.

— Overall incentive compensation is awarded based on both corporate objectives and individual performance objectives.

— Long term incentives are comprised of incentive stock options and restricted share unit (“RSUs”).

— In 2013, Mr. Friedland, Founder and Executive Co-Chairman, voluntarily waived a salary for acting as an executive of the Company and did not participate in the compensation program for executives. Although Mr. Friedland remains eligible to receive incentive compensation as determined by the Compensation Committee and the Board from time to time, he did not receive any such compensation in 2013.

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In 2013, the individuals who served as our principal executive officer, our principal financial officer and the other three most highly compensated executive officers as of the end of 2013 (the "Named Executive Officers" or "NEOs") were:

NEO	Position Held
Carlos A Cabrera	Executive Chairman
Gerald D. Schiefelbein	SVP, Finance & Chief Financial Officer
Santiago Pástor Morris	SVP, President & General Manager Ecuador
Edwin J. Veith	SVP, Canadian Projects
Joseph D. Kuhach	SVP, Upstream Technology & Integration

Compensation Committee

The Company's executive compensation program is administered by the Compensation Committee. The Compensation Committee's responsibilities include the following:

— reviewing and approving corporate goals and objectives for the principal executive officer's compensation, evaluating his performance and setting his compensation level;

— reviewing and making recommendations to the Board with respect to the adequacy and form of compensation and benefits of all executive officers and directors;

— administering and making recommendations to the Board with respect to the Company's incentive compensation plans and equity-based plans;

— reviewing the Company's compensation program and the specific performance objectives and targets set to establish short term and long term incentive awards;

— recommending to the Board the principal executive officer's performance evaluation which takes into consideration the principal executive officer's annual objectives as established by the Board and input the Committee has received from other Board members with respect to the principal executive officer's performance; and

— determining the recipients of, and the nature and size of share compensation awards and bonuses granted from time to time.

Compensation Committee Interlocks and Insider Participation

All Compensation Committee members are independent directors. The Committee met five times during 2013 and twice during the first quarter of 2014. All meetings of the Committee are documented in the form of meeting minutes. The Committee is made up of the following members, all of whom have experience in dealing with compensation matters:

— Mr. Howard Balloch has served as the Chair of the Company's Compensation Committee since 2004. He served as the Chair of the Nominating and Corporate Governance Committee from 2003 until 2012. Mr. Balloch has also served on the compensation committees of Ivanhoe Mines Ltd., now Turquoise Hill Resources Ltd., and Methanex Corporation. He was until March 2013, the Chairman of Canaccord Genuity Asia Limited, a boutique investment banking firm that provides financial advisory services, and chaired its Compensation Committee (management level). In these various roles, Mr. Balloch has had frequent interaction with professional compensation advisors with matters pertaining to executive and director compensation;

— Mr. Brian Downey has served as a member of the Compensation Committee since May 2006. He was the President and Chief Executive Officer of the Credit Union Central of Canada from 1986 to 1995 and the Chief Executive Officer of Lending Solutions, Inc. from November 1995 to January 2002. During Mr. Downey's career in the financial services industry, he has had extensive experience with matters pertaining to senior management compensation;

— Dr. Robert Graham was appointed to the Compensation Committee in April 2013. He has been the Chairman and Chief Executive Officer of Ensyn Corporation and its predecessor companies since 1984. He is Canada's pre-eminent authority in his field of applied engineering (fast thermal conversion), and has been working on the commercial development of Ensyn's RTP™ biomass refining and petroleum upgrading technologies since the early 1980 s. In his role as the Chairman and Chief Executive Officer of Ensyn, Dr. Graham has regularly addressed matters of executive and director compensation with Ensyn employees, external compensation consultants and human resource professionals; and

— Mr. A. Robert Abboud has been an ex-officio member of the Compensation Committee since April 2013, having previously served on the Compensation Committee from April 2012 to April 2013 and from May 2008 to May 2010. Mr. Abboud has enjoyed a business career spanning more than 55 years and has extensive executive management experience involving compensation matters, including serving as CEO and COO of public companies and having served on the compensation committees of several public companies and not-for-profit organizations.

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In establishing policies covering base salaries, benefits, annual incentive bonuses and long term incentives, the Compensation Committee takes into consideration the recommendations of management. The Compensation Committee may seek compensation advice where appropriate from external consultants. When the Compensation Committee considers it necessary or advisable, it may retain, at the Company's expense, outside consultants or advisors to assist or advise the Committee on any matter within its mandate. The Committee has the sole authority to retain and terminate any such consultants or advisors.

In the second quarter of 2010, the Compensation Committee engaged the services of the consulting firm Mercer Canada Ltd. ("Mercer") to undertake a comprehensive review of executive compensation for executive positions and other senior management positions, including the development of a comparator group for the Company to help the Company establish its compensation plan components with reference to its peers (the "Mercer Study"). No external consultants were hired during 2013, although the Company does review and participate in certain market studies as to compensation market standards, including the Mercer Total Compensation Survey for Energy Sector published in August of each year setting out reward levels as a general benchmark for industry in Canada (the "Mercer Annual Market Study"). In 2013, no fees were paid to compensation consultants, apart from nominal fees to participate in market studies, including the Mercer Annual Market Study.

Compensation and Benefits Philosophy and Goals

In determining the nature and quantum of compensation for the Company's executive officers the Company is seeking to achieve the following objectives, in approximately an equal level of importance:

— to provide a strong incentive to management to contribute to the achievement of Ivanhoe's short term and long term corporate goals;
— to ensure that the interests of Ivanhoe's executive officers and the interests of the Company's shareholders are aligned;
— to ensure that Ivanhoe is able to attract, retain and motivate executive officers of the highest caliber in light of the strong competition in the oil and gas industry for qualified personnel;
— to recognize that the successful implementation of Ivanhoe's corporate strategy cannot necessarily be measured, at this stage of its development, only with reference to quantitative measurement criteria of corporate or individual performance; and
— to provide fair, transparent, and defensible compensation.

In addition, the Company strives to follow guiding principles to be cost effective and competitive, to promote internal equity, to represent both value of the job and value of the person, to link compensation decisions to results, and to both be responsive to local factors within a global outlook.

NEOs and directors are not permitted to purchase financial instruments, including, for greater certainty, prepaid variable forward contracts, equity swaps collars, or units of exchange funds, that are designed to hedge or offset a decrease in market value of equity securities granted as compensation or held, directly or indirectly, by the NEO or director in accordance with the Company's Corporate Disclosure, Confidentiality and Securities Trading Policy.

How the Company Makes Compensation Decisions

The Compensation Committee oversees and sets the general guidelines and principles for the implementation of the Company's executive compensation policies, assesses the individual performance of the Company's executive officers and makes recommendations to the Board of Directors. Based on these recommendations, the Board of Directors makes decisions concerning the nature and scope of the compensation to be paid to the Company's executive officers. The Compensation Committee bases its recommendations to the Board on Ivanhoe's compensation philosophy and on individual and corporate performance.

The Compensation Committee annually reviews, and recommends to the Board, the cash compensation, any annual performance bonus, long term incentive grants and overall compensation package for each of the Company's executive officers.

Decisions for base salary adjustments are usually made during the first quarter of the new fiscal year. In the normal course of business, corporate goals and certain individual goals upon which performance bonuses are, in part, made for a fiscal year are set at the beginning of the fiscal year, and decisions on actual bonuses and incentive awards are reviewed during the first quarter following the end of the fiscal year and awarded as soon as practicable thereafter. Management presents its compensation recommendations for consideration by the Compensation Committee. The Compensation Committee presents its recommendations for overall compensation for base pay, bonuses and incentives to the Board for its approval.

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Notwithstanding the adoption of a more formalized approach following the development of the Company's compensation plan in 2010, based on the Mercer Study, the Compensation Committee and the Board retain a significant level of discretion in making compensation decisions, particularly in determining the satisfaction of broad performance criteria and overall personal performance in determining the percentage of target bonus and long term incentive that is ultimately awarded within the established bonus framework. The Compensation Committee and Board also retain flexibility in making compensation awards outside of the compensation plan framework where circumstances justify such awards.

In designing and implementing the Company's compensation policy the Compensation Committee and the Board regularly assess, as part of their respective deliberations, the risks associated with the Company's policies and practices. The structure of incentive compensation for executives is designed not to focus on a single metric, which in the Company's view could be distortive, but instead a combination of both corporate and personal objectives as well as discretion in the ultimate awards, that balance both long term and short term objectives and a subjective view of overall performance. The policies are designed to preserve cash to the extent practicable, with executives participating in the upside potential of the Company through stock options and RSUs that aim to mirror shareholder returns. Consideration of risk is also directly incorporated into the incentive compensation by including compliance as an important factor in corporate objectives for bonus and long term incentive awards.

Peer Comparator Group

The comparator group for the Company for purposes of developing the compensation program includes oil and gas companies with international operations, oil sands operations and similar market capitalization. The comparator group included Pacific Rubiales Energy Corporation, Black Pearl Resources Inc., Niko Resources Ltd., Connacher Oil & Gas Ltd., Athabasca Oil Sands Corporation, OPTI Canada Inc., Petrobank Energy & Resources Ltd., TransGlobe Energy Corporation, Bankers Petroleum Ltd., Ithaca Energy Inc., Gran Tierra Energy Inc., Calvalley Petroleum Inc., Paramount Resources Ltd., Pan Orient Energy Corporation, Southern Pacific Resources Corporation and Transatlantic Petroleum Ltd. For compensation decisions in 2013, specific reference was not made to this comparator group but rather benchmarking at the median (for salary) and seventy-fifth percentile (for overall compensation) was done with reference to appropriate data from the Mercer Annual Market Study, adjusted for inflation.

Elements of Total Compensation

The compensation package that the Company provides to its executive officers generally consists of base salary, annual performance bonuses and equity incentives. The Company's compensation policy reflects a belief that an element of total compensation for the Company's executive officers should be "at risk" and in the form of common shares or incentive stock options so as to create a strong link to build shareholder value. In setting compensation levels, the Compensation Committee takes into account an executive's past performance, future expectations for performance and also considers both the cumulative compensation being granted to executives as well as internal and external equity amongst the Company's executives. At this stage of the Company's development, the Company also considers the available cash resources of the Company.

The following summarizes the primary purpose of each compensation element and its emphasis:

- base salary – paid in cash as a fixed amount of compensation for performing the day to day responsibilities of the job;
- performance bonus – annual award, paid in cash and earned for the achievement of near term critical strategic corporate and project goals; and
- long term incentive awards – annual equity award, in the form of a combination of stock options and RSUs, granted to align the interests of the executive with longer term company goals, the creation of shareholder value and the retention of key executives.

Base Salary

The base salaries of the Company's executive officers are determined at the commencement of employment as an executive officer by the terms of the executive officer's employment contract. The base salary is determined by a subjective assessment of each individual's performance, experience and other factors the Company believes to be relevant, including prevailing industry demand for personnel having comparable skills and performing similar duties, the compensation the individual could reasonably expect to receive from a competitor and the Company's ability to pay.

Under the Company's compensation program and onward, salary levels are to be assessed using a pay grade system that is consistent with industry practice. Each of the Company's employees, including the Company's executive officers, is placed in a pay grade based upon his or her position, knowledge, skills, relevant experience and credentials. Annual salary

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increases are made based on performance and the relative position within a pay grade. The Compensation Committee also considers retention risks, succession requirements and compensation changes in the market in determining salary changes. Salary targets for executives are generally targeted at a median salary determined, in 2013, with reference to the relevant ranges set out in the Mercer Annual Market Study.

Cash Performance Bonus

The annual bonus program is intended to align the performance of the Company's employees with the near term critical goals defined in the annual business plan. The program calls on the same pay grade system used to establish base salary to be used for determining the bonus targets for each employee.

Under the compensation plan for 2011 and onwards, cash bonuses are awarded to the Company's executive officers and senior non-executive management based on the performance of the Company, the success in meeting, or exceeding, defined corporate and individual performance targets and the discretionary assessment of the executive's performance by the Compensation Committee and the Board. For executive officers, potential bonus awards can range from 55% to 75% of base salary multiplied by a weighted achievement factor ranging from 0% to 200%.

Long Term Incentive Plan

Equity based compensation is granted to the Company's executive officers and management. This long term incentive portion of compensation is meant to retain key employees over the long term and to focus the efforts of those individuals on shareholder return and the longer broader goals of the organization. To remain competitive within the industry, equity grants in the form of stock options and RSUs are used to enhance the overall total compensation package.

Equity based compensation is determined as a percentage of base pay and may have a combination of stock option grants and RSUs, the combination of which is determined by the pay grade level. The higher the grade level the higher the weighting towards "at risk" stock option grants.

All outstanding stock options that have been granted under the Company's Equity Incentive Plan were granted at prices not less than 100% of the fair market value of the Company's common shares on the dates such options were granted. In addition, the Board of Directors has traditionally taken an approach to vesting that is based on the passage of time and option exercise periods and vesting schedules for options granted to executive officers are determined by the Compensation Committee and the Board of Directors.

During 2011, the Company established an RSU Plan to provide a form of equity-linked compensation that is less dilutive than options as the RSU Plan does not involve any issue of shares from treasury. The RSU Plan is administered by the Board which has the power make decisions about the awarding of RSUs. The awards under the RSU Plan consist of RSUs which, upon vesting, may be settled in cash or common shares of the Company purchased on the TSX through a Trustee. Generally RSUs vest in thirds on the first, second, and third anniversaries of the date of grant. On the date of vesting, employees are entitled to receive one common share for each vested RSU. In lieu of common shares, employees may receive a cash amount equal to the fair market value of the common shares then deliverable. Employees who are taxpayers in jurisdictions outside Canada and those individuals who are non-employee service providers may only receive cash in exchange for their vested RSUs. If an employee voluntarily leaves the employment of the Company any unvested RSUs are forfeited by the employee under the terms of the RSU Plan. In the event of a termination without cause, as defined in the RSU Plan, all unvested RSUs are terminated six months after the date of termination; provided however that in the event such termination without cause occurs within six months following a change of control, all unvested RSUs vest on the earlier of the next vesting date for the applicable RSU award and the effective time of such termination.

While the Compensation Committee and the Board retain flexibility in apportioning long term incentive compensation as between stock options and RSUs, the targeted allocation for NEOs is generally expected to be in the range of 60% to 80% weighting for stock options and 20% to 40% for RSUs for a given award.

Long term incentive awards granted under the compensation plan are awarded according to performance and the success in meeting or exceeding the annual established corporate and project targets. For NEOs, potential value of equity grants can range from 160% to 225% of base salary multiplied by a weighted achievement factor ranging from 0% to 200%.

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EXECUTIVE COMPENSATION DECISIONS

Salary Compensation

In 2014, the base salary for the Executive Chairman remained constant at $606,100.

Robert M. Friedland, Founder and Executive Co-Chairman, has voluntarily waived a cash salary from the Company.

In 2014, the base salaries for all other NEO's were increased based on an overall budget of 3.8%. Individual NEO base salary adjustments were determined with reference to externally generated compensation data from the Canadian oil and gas industry and individual performance ratings recommended by the Executive Chairman to the Compensation Committee.

Short Term and Long Term Incentive Compensation Awards Made in 2014 Relating to 2013 Performance

The following chart sets out the value of bonus (short term incentive) and long term incentive compensation awarded during 2014 relating to 2013 performance for each of the NEOs receiving such compensation in 2014.

Name	2013 Salary ($)	Maximum Target Bonus ($)	Maximum Target Long Term Incentive ($)	Percentage of Maximum Target Awarded	Bonus Awarded ($)	Long Term Incentive Awarded(2) ($)	
Carlos A. Cabrera	672,923	909,150	2,727,450	10.0 %	–	272,745	(3)
Gerald D. Schiefelbein(1)	284,073	334,620	973,440	5.5 %	–	53,179	(4)
Santiago Pástor Morris	321,468	357,019	1,038,602	5.9 %	–	61,722	(5)
Edwin J. Veith	295,993	325,592	947,178	6.0 %	–	56,831	(6)
Joseph D. Kuhach	312,000	343,200	998,400	6.0 %	–	59,904	(7)

(1) Amounts paid in Canadian dollars to Mr. Schiefelbein were converted to US currency based on the Bank of Canada monthly average exchange rate during the pay periods.

(2) The value of the stock options awarded is the estimated fair value on date of grant calculated using the Black-Scholes option pricing model, with the following assumptions: an estimated volatility equal to the historical volatility of the Company's common shares over a period equal to the expected life of the option, an estimated dividend yield of $nil, a risk free rate of return equal to the rate currently available on federal government zero-coupon bonds with a term equal to the expected life of the option and an expected life approximating the term of the option. The value of stock options with a Canadian dollar exercise price was converted to US dollars using the Bank of Canada closing exchange rate on date of grant, for example, Cdn$1.00 to US$0.910 on February 17, 2014. The value of the RSUs awarded is the estimated fair value on date of grant, which is calculated as the number of RSUs awarded multiplied by the weighted average price of the Company's common shares for the five trading days immediately preceding the date of grant, converted to US dollars using the Bank of Canada closing exchange rate on date of grant.

(3) Consists of 87,982 RSUs which vest as to one third on each of February 17 of 2015, 2016 and 2017, options to purchase 436,392 common shares exercisable at Cdn$0.68, expiring on February 17, 2021, and vesting as to 25% on each of February 17 of 2015, 2016, 2017 and 2018.

(4) Consists of 34,357 RSUs which vest as to one third on each of February 17 of 2015, 2016 and 2017, options to purchase 64,896 common shares exercisable at Cdn$0.68, expiring on February 17, 2021, and vesting as to 25% on each of February 17 of 2015, 2016, 2017 and 2018.

(5) Consists of 39,821 RSUs which vest as to one third on each of February 17 of 2015, 2016 and 2017, options to purchase 74,066 common shares exercisable at Cdn$0.68, expiring on February 17, 2021, and vesting as to 25% on each of February 17 of 2015, 2016, 2017 and 2018.

(6) Consists of 36,665 RSUs which vest as to one third on each of February 17 of 2015, 2016 and 2017, options to purchase 68,197 common shares exercisable at Cdn$0.68, expiring on February 17, 2021, and vesting as to 25% on each of February 17 of 2015, 2016, 2017 and 2018.

(7) Consists of 38,648 RSUs which vest as to one third on each of February 17 of 2015, 2016 and 2017, options to purchase 71,885 common shares exercisable at Cdn$0.68, expiring on February 17, 2021, and vesting as to 25% on each of February 17 of 2015, 2016, 2017 and 2018.

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The following chart sets out the corporate performance objectives applicable to NEOs receiving annual incentive compensation in respect of 2013, these performance objectives were set at the beginning of the year and included such elements as the securing of sufficient financing to deliver on corporate commitments and refund working capital reserves, the advancing of commercialization of the HTL® technology, achieving production reserve and share price growth, and achieving a good corporate record in employee health and safety and in ensuring a spotless environmental record. The principal weighting for corporate goals (approximately 40%) was set on achieving financing objectives, with the other corporate objectives having weightings at between 5% and 20%. Given the significant weighting to financing goals which were exceeded, the net corporate goals were determined to be 20% of the targeted maximum for 2013.

Corporate Performance Objectives (In Respect of 2013 Performance)	Performance Results
Financing: Meet: Sufficient funds to meet subsequent years planned capital, operating and general and administrative expenditures and/or success in other project funding initiatives; Exceed: Sufficient funds to meet 200% subsequent years' planned capital, operating and general and administrative expenditures and/or success in other project funding initiatives	Not achieved
Reserve Growth: Meet: increased reserves by 3%; Exceed: increased reserves by 6%	Not achieved
Production & Cash Flow: Meet: increased incremental working interest production by 258%; Exceed: increased incremental working interest production by 517%	Not achieved
Commercialize HTL®: Establish agreements to proceed in partnership with 3rd party organizations	Not achieved
Share Price Appreciation: Meet: share price increase of 50%; Exceed: share price increase of 100%	Not achieved
Environment: Meet: Less than 2 recordable incidents; Exceed: Zero recordable or reportable incidents	Exceeded
Safety: Meet: Company TRIR is industry average; Exceed: Zero lost time incidents or recordable incidents	Exceeded

As Executive Chairman, Mr. Cabrera's performance is rated on corporate objectives as well as a discretionary assessment of his overall job performance.

In the case of the other NEO's the judgment was based on a mix of 60% corporate objectives and 40% performance objectives for each such executive as well as a discretionary assessment of overall job performance.

Mr. Schiefelbein is rated on his personal achievements with respect to the external reporting, tax, regulatory compliance and Information Systems management.

Mr. Pástor Morris is rated on achievement of his personal objectives largely related to the further development of the Pungarayacu project, as well as his contribution to the future development of Latin America projects.

Mr. Veith is rated on achievement of his personal objectives largely related to the further development of the Tamarack Project, as well as his contributions to corporate finance activities of the Company.

Mr. Kuhach is rated on achievement of his personal objectives largely related to the successful creation of the Centers of Excellence and his contribution to the development of the Tamarack Project.

Taking into account the financial situation of the Company, the Board, on the recommendation of the Compensation Committee, did not authorize cash bonuses to the NEO's for 2013 regardless of individual performances justifying such bonuses.

For 2013 the Compensation Committee and the Board has authorized a Long Term Incentive award to all NEO's based on achievement of a 20% corporate performance which is weighted at 100% for the Executive Chairman and 60% for all other NEO's. This award resulted in a final amount of 12% of their potential LTI award for NEO's and a 20% award for the Executive Chairman.

Other Compensation

Employees of Ivanhoe Energy Holdings Inc. may participate in Ivanhoe's 401(k), a defined contribution plan that includes employee and company contributions. See also "Pension Plan" below. In 2013, Mr. Veith was paid $23,000 for the purpose of contributing to his 401(k) retirement plan as well as $128,529 as an expatriate uplift. In 2013, Mr. Kuhach was paid $23,000 for the purpose of contributing to his 401(k) retirement plan as well as $144,000 as an expatriate uplift. In 2012, Mr. Cabrera was paid $23,000 for the purpose of contributing to his 401(k) retirement plan. In 2013, Mr. Pástor Morris received a benefit of $49,752 attributed to the value of a lease agreement for a company vehicle. In addition, Mr. Pástor Morris received a cash settlement of $85,715 for consideration for retirement savings and educational allowances.

All NEOs participate in insurance plans offered to all employees, including group life insurance, accidental death and dismemberment, Business Travel Accidental coverage and Supplemental Business Travel Medical coverage calendar year.

Performance Graph

The following graph shows the change in a Cdn$100 investment in Ivanhoe common shares over the past five years, compared to the S&P/TSX Composite Index, the S&P/TSX Oil & Gas Exploration & Production and the S&P/TSX Energy Sector Index as at December 31, 2013. The Company's common shares were part of the S&P/TSX Composite Index from March 22, 2010 until December 9, 2011.

The trend in overall compensation paid to the Company's executive officers over the past five years has not specifically tracked the performance of the market price of the Company's common shares, or the S&P/TSX Composite Index, particularly since 2008. Overall compensation for NEOs increased during the period.

Option-Based Awards

Please see the section "Long Term Incentives Plan" in the Compensation Discussion and Analysis for a discussion of the Company's approach to option-based awards.

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In 2013, the Company issued option-based awards under its Equity Incentive Plan to executive officers as described under the heading "Executive Compensation Decisions."

COMPENSATION TABLE

The following table sets forth all compensation earned by the individuals who served as our NEOs. Our NEOs may change from year to year due to fluctuations in our executive officers' annual compensation.

Name and Principal Position	Year	Salary(1) ($)	Share-Based Awards(2) ($)	Option-Based Awards(3) ($)	Non-Equity Incentive Plan Compensation - Annual Incentive Awards(4) ($)	Pension Value ($)	All Other Compensation ($)	Total Compensation ($)
Carlos A. Cabrera	2013	672,923	54,549	218,196	–	23,000	–	968,668
Executive Chairman	2012	611,378	628,687	1,535,221	750,000	22,500	–	3,547,786
	2011(5)	27,237	–	421,316	–	–	99,870 (6)	548,423
Gerald D. Schiefelbein	2013	284,073	21,272	31,907	–	–	4,360	341,612
SVP, Finance	2012	297,347	188,276	286,232	167,027	–	918	939,800
& Chief Financial Officer	2011	287,567	110,717 (9)	166,075 (9)	95,148	–	–	659,507
Santiago Pástor Morris	2013	321,468	24,689	37,033	–	–	135,467	518,657
SVP,	2012	305,427	204,150	310,363	83,567	–	87,280	990,787
President and General Manager Ecuador	2011	289,297	321,742	172,728	14,494	–	76,477	874,738
Edwin J. Veith	2013	295,993	22,732	34,098	–	23,000	133,767 (7)	509,590
SVP, Canadian Projects	2012	283,032	188,877	287,144	167,559	22,500	160,896	1,110,008
	2011	274,176	97,387 (9)	146,081 (9)	83,692	20,400	71,654	693,390
Joseph D. Kuhach	2013	312,000	23,962	35,942	–	23,000	149,238 (8)	544,142
SVP,	2012	266,333	198,505	373,419	176,101	22,500	213,143	1,250,001
Upstream Technology & Integration	2011	239,208	157,691	110,150	75,000	22,500	127,532	732,081

(1) Amounts paid in Canadian dollars to Mr. Schiefelbein were converted to US currency based on the Bank of Canada monthly average closing exchange rate during the pay periods.

(2)

The value of the RSUs awarded is the estimated fair value on date of grant, which is calculated as the number of RSUs awarded multiplied by the weighted average price of the Company's common shares for the five trading days immediately preceding the date of grant, converted to US dollars using the Bank of Canada exchange rate on date of grant.

(3) The value of the stock options awarded is the estimated fair value on date of grant calculated using the Black-Scholes option pricing model, with the following assumptions: an estimated volatility equal to the historical volatility of the Company's common shares over a period equal to the expected life of the option, an estimated dividend yield of $nil, a risk free rate of return equal to the rate currently available on federal government zero-coupon bonds with a term equal to the expected life of the option and an expected life approximating the term of the option. The value of stock options with a Canadian dollar exercise price was converted to US dollars using the Bank of Canada closing exchange rate on date of grant.

(4) Cash bonuses in respect of a year's performance are awarded in the subsequent year but recorded in the year in respect of which the compensation is awarded. Cash bonuses paid to Mr. Schiefelbein was converted to US currency based on the Bank of Canada monthly average closing exchange rate during the pay period.

(5) Mr. Cabrera was appointed as Executive Chairman, effective December 12, 2011 and was employed for approximately one half month in 2011.

(6) Mr. Cabrera is also a director of the Company. Pursuant to the Company's policies regarding management directors, Mr. Cabrera did not receive compensation from the Company for acting as a director subsequent to his appointment as Executive Chairman. Prior to his appointment, Mr. Cabrera earned $91,323 in option-based awards and $99,870 in fees for his service as a director in 2011.

(7) Mr. Veith received $133,767 as an expatriate uplift in 2013. The amount of income taxes payable by Ivanhoe in connection with Mr. Veith's 2013 compensation is estimated at $165,516.

(8) Mr. Kuhach received $149,238 as an expatriate uplift in 2013. The amount of income taxes payable by Ivanhoe in connection with Mr. Kuhach's 2013 compensation is estimate at $204,841.

(9) The values for share-based awards and option based awards were recorded in our 2011 10-K under "All Other Compensation" as the estimated value of compensation still to be awarded as stock options and/or RSUs later in 2011.

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INCENTIVE PLAN AWARDS

To value stock options awarded to our NEOs, we used the Black-Scholes option pricing model. The actual value realized on exercises may be higher or lower depending on our common share price at the time of exercise.

Outstanding option-based awards at December 31, 2013

	Option Awards				Share-Based Awards	
Name	Number Of Securities Underlying Unexercised Options(3) (#)	Option Exercise Price(3) ($)	Option Expiration Date	Total Value of Unexercised Options(1) (US$)	Number of RSUs That Have Not Vested(3) (#)	Market Value of RSUs That Have Not Vested (US$)(2)
Carlos A. Cabrera	983,447	2.22	Feb 21, 2020	–	173,742	104,545
Executive Chairman	216,667	2.76	Dec 16, 2018	–		
	66,667	6.00	Jul 28, 2017	–		
	33,333	7.89	May 18, 2017	–		
	16,667	7.95	Apr 28, 2018	–		
Gerald D. Schiefelbein	183,357	2.22	Feb 21, 2020	–	118,233	71,144
SVP, Finance & Chief Financial Officer	80,889	2.94	Mar 26, 2019	–		
	42,898	7.95	May 24, 2018	–		
	43,333	6.84	Oct 28, 2017	–		
	66,667	7.53	Oct 1, 2016	–		
Santiago Pástor Morris	198,815	2.22	Feb 21, 2020	–	130,592	78,581
SVP, President and General Manager Ecuador	49,595	2.94	Mar 26, 2019	–		
	6,944	7.95	May 24, 2018	–		
	33,334	6.84	Oct 28, 2017	–		
	26,667	9.78	Apr 29, 2017	–		
Edwin J. Veith	183,941	2.22	Feb 21, 2020	–	114,399	68,837
SVP, Canadian Projects	71,608	2.94	Mar 26, 2019	–		

	43,333	6.84	Oct 28, 2017	–		
	35,150	7.95	May 24, 2018	–		
	50,000	6.66	Sep 17, 2014	–		
Joseph D. Kuhach	193,319	2.22	Feb 21, 2020	–	132,707	79,854
SVP, Upstream Technology	66,667	1.68	Sep 25, 2019	–		
& Integration	50,937	2.94	Mar 26, 2019	–		
	26,667	6.84	Oct 28, 2017	–		
	17,361	7.95	May 24, 2018	–		
	26,667	6.66	Sep 17, 2014	–		

(1) Calculated as the difference between the December 31, 2013, closing market price of the Company's common shares and the exercise price of the options, multiplied by the number of unexercised options. The value of options with a US dollar exercise price is calculated using the NASDAQ closing price of $0.62 per common share. The value of options with a Canadian dollar exercise price is calculated using the TSX closing price of Cdn$0.64 per common share and converted to US dollars using the December 31, 2013, Bank of Canada closing rate. Where the exercise price exceeds the market value per common share, the value is zero.

(2) Calculated as the December 31, 2013, closing market price of the Company's common shares multiplied by the number of unexercised RSUs and converted to US dollars using the December 31, 2013, Bank of Canada closing rate.

(3) On April 22, 2013, the Company proceeded with a three for one common share consolidation that resulted in proportionate adjustments to outstanding stock options and RSUs.

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Incentive plan awards – value vested in 2013

Name	Option-Based Awards Value Vested During the Year(1) (US$)	Share-Based Awards Value Vested During the Year (2) (US$)
Carlos A. Cabrera	–	–
Gerald D. Schiefelbein	–	11,857
Santiago Pástor Morris	–	11,867
Edwin J. Veith	–	10,996
Joseph D. Kuhach	–	10,634

(1) Calculated as the difference between the closing market price of the Company's common shares on the vesting date and the exercise price of the options, multiplied by the number of options vesting in the current year. The value of options with a Canadian dollar exercise price were converted to US dollars using the Bank of Canada closing rate on the vesting date. Where the exercise price exceeds the market price per common share, the value is zero.

(2) Calculated as the December 31, 2013, closing market price of the Company's common shares multiplied by the number of vested RSUs and converted to US dollars using the December 31, 2013, Bank of Canada closing exchange rate.

PENSION PLAN

Employees of Ivanhoe Energy Holdings Inc. (the "Employees") may participate in Ivanhoe's 401(k) (the "Plan"). The Plan is a defined contribution plan that includes Employee and Company contributions. Employees may contribute up to the maximum amount established by the Internal Revenue Code and the Company may elect to make annual discretionary matching and profit sharing contributions. Employee contributions vest immediately and Company contributions vest after two years of service. Investment decisions are made by the Employee from a variety of investment options.

The following table represents the value of accumulated pension assets within the Plan for Messrs. Cabrera, Kuhach, and Veith. There were no above-market or preferential earnings provisions.

Name	Accumulated Value at January 1, 2013 ($)	Compensatory(1) ($)	Non-compensatory(2) ($)	Accumulated Value at December 31, 2013 ($)
Carlos A. Cabrera	22,550	34,922	34,922	92,394
Edwin J. Veith	325,781	33,229	35,297	394,307
Joseph D. Kuhach	295,123	50,164	52,342	397,629

(1) Represents employer contributions, distributions and earnings.
(2) Represents employee contributions, distributions and earnings.

TERMINATION AND CHANGE OF CONTROL BENEFITS

The Company has written contracts of employment with Messrs. Cabrera, Schiefelbein, Pástor Morris, Kuhach and Veith. In the case of termination for cause or voluntary resignation, the employment contracts do not result in incremental payments, payables or benefits, and therefore have been excluded from the following discussion. Perquisites and other personal benefits totaling less than $50,000 have also been omitted.

Estimated incremental payments are based on the individual's annual salary as at December 31, 2013. Any amounts payable in Canadian dollars have been translated to US dollars using the December 31, 2013, Bank of Canada closing rate. Unexercised stock options were valued using the December 31, 2013, closing market price of the Company's common shares and stock options with a Canadian dollar exercise price were converted to US dollars using the December 31, 2013, Bank of Canada closing rate. Unexercised RSUs were valued using the December 31, 2013 closing market price of the Company's common shares multiplied by the number of unexercised RSUs and converted to U.S. dollars using the December 31, 2013 Bank of Canada closing rate.

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Carlos A. Cabrera

Mr. Cabrera's employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would otherwise have vested during the succeeding twelve months to vest immediately and generally remain exercisable for six months;

(b) in the case of termination of the employment contract by the Company within twelve months of a change of control, the Company must pay a lump sum equal to two times the sum of i) Mr. Cabrera's current salary, and ii) the average of the two highest value aggregate annual performance bonuses paid to Mr. Cabrera by the Company during the two completed fiscal years of the Company in which Mr. Cabrera was employed by the Company that preceded the date of such termination. All stock options will vest immediately and generally remain exercisable for six months;

(c) Mr. Cabrera is bound by a non-competition clause effective until the later of twelve months after the termination of active employment or the date he no longer receives compensation of any kind under the employment contract;

(d) Mr. Cabrera is bound by a non-solicitation clause effective for twelve months after the termination of active employment; and

(e) Mr. Cabrera is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Cabrera in the above scenarios are (a) a lump sum of $606,100, the accelerated vesting and delivery of 173,742 RSUs, valued at $104,545 and accelerated vesting of stock options valued at $nil; and (b) a lump sum of $1,212,200, the accelerated vesting and delivery of 173,742 RSUs, valued at $104,545 and accelerated vesting of stock options valued at $nil.

Gerald D. Schiefelbein

Mr. Schiefelbein's employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would otherwise have vested during the succeeding twelve months to vest immediately and to remain exercisable for twelve months (subject to earlier expiration), cause all of the unvested RSUs that would otherwise have vested during the succeeding twelve months to vest immediately and deliver those RSUs that have, or are deemed to have, vested to Mr. Schiefelbein;

(b) in the case of: i) termination of the employment contract by the Company, other than in the case of termination for just cause or disability; or ii) resignation for just cause, in either case, within twelve months of a change of control, the Company must pay twelve months wages in a lump sum, cause all of the vested stock options to remain exercisable for twelve months (subject to earlier expiration) and cause all RSUs, vested or unvested on the date of termination, to be deemed vested and deliverable to Mr. Schiefelbein. If the termination referred to in i) occurs forthwith following a change of control, all of the unvested stock options held by Mr. Schiefelbein shall vest immediately and remain exercisable for twelve months (subject to earlier expiration);

(c) on the occurrence of (a) or (b), if the criteria for earning a milestone bonus under his employment arrangements are satisfied (whether prior to the date of termination or subsequent to the date of termination but prior to the date by which such criteria were to be met), Mr. Schiefelbein shall be entitled to such milestone bonus effective as of the date that the applicable milestones are reached;

(d) Mr. Schiefelbein is bound by a non-competition clause effective until the later of twelve months after the termination of active employment or the date he no longer receives compensation of any kind under the employment contract;

(e) Mr. Schiefelbein is bound by a non-solicitation clause effective for twelve months after the termination of active employment; and

(f) Mr. Schiefelbein is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Schiefelbein in the above scenarios are: (a) a lump sum of Cdn$316,318, the accelerated vesting and delivery of 118,233 RSUs, valued at $71,144 and accelerated vesting of stock options valued at $nil; and (b) a lump sum of Cdn$316,318, the accelerated vesting and delivery of 118,233 RSUs, valued at $71,144 and, assuming termination occurs forthwith following a change of control, accelerated vesting of stock options valued at $nil. In addition to the foregoing payments under each of scenarios (a) and (b) and assuming full satisfaction of all applicable criteria under scenario (c), Mr. Schiefelbein would be entitled to a milestone bonus of up to Cdn$174,002, being 55% of base salary.

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Santiago Pástor Morris

Mr. Pástor Morris's employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would otherwise have vested during the succeeding twelve months to vest immediately and to remain exercisable for twelve months (subject to earlier expiration), cause all of the unvested RSUs that would otherwise have vested during the succeeding twelve months to vest immediately and deliver those RSUs that have, or are deemed to have, vested to Mr. Pástor Morris;

(b) in the case of: i) termination of the employment contract by the Company, other than in the case of termination for just cause or disability; or ii) resignation for just cause, in either case, within twelve months of a change of control, the Company must pay twelve months wages in a lump sum, cause all of the vested stock options to remain exercisable for twelve months (subject to earlier expiration) and cause all RSUs, vested or unvested on the date of termination, to be deemed vested and deliverable to Mr. Pástor Morris. If the termination referred to in i) occurs forthwith following a change of control, all of the unvested stock options held by Mr. Pástor Morris shall vest immediately and remain exercisable for twelve months (subject to earlier expiration);

(c) on the occurrence of (a) or (b), if the criteria for earning a milestone bonus set out in his employment agreement are satisfied (whether prior to the date of termination or subsequent to the date of termination but prior to the date by which such criteria were to be met), Mr. Pástor Morris shall be entitled to such milestone bonus effective as of the date that the applicable milestones are reached;

(d) Mr. Pástor Morris is bound by a non-competition clause effective until the later of twelve months after the termination of active employment or the date he no longer receives compensation of any kind under the employment contract;

(e) Mr. Pástor Morris is bound by a non-solicitation clause effective for twelve months after the termination of active employment; and

(f) Mr. Pástor Morris is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Pástor Morris in the above scenarios are: (a) a lump sum of $332,719, the accelerated vesting and delivery of 130,592 RSUs, valued at Cdn$78,581 and accelerated vesting of stock options valued at $nil; and (b) a lump sum of $332,719, the accelerated vesting and delivery of 130,592 RSUs, valued at $78,581 and accelerated vesting of stock options valued at $nil. In addition to the foregoing payments under each of scenarios (a) and (b) and assuming full satisfaction of all applicable criteria under scenario (c), Mr. Pástor Morris would be entitled to a milestone bonus of up to a maximum of $182,995, being 55% of base salary.

Edwin J. Veith

Mr. Veith's employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would otherwise have vested during the succeeding twelve months to vest immediately and to remain exercisable for twelve months (subject to earlier expiration), cause all of the unvested RSUs that would otherwise have vested during the succeeding twelve months to vest immediately and deliver those RSUs that have, or are deemed to have, vested to Mr. Veith;

(b) in the case of: i) termination of the employment contract by the Company, other than in the case of termination for just cause or disability; or ii) resignation for just cause, in either case, within twelve months of a change of control, the Company must pay twelve months wages in a lump sum, cause all of the vested stock options to remain exercisable for twelve months (subject to earlier expiration) and cause all RSUs, vested or unvested on the date of termination, to be deemed vested and deliverable to Mr. Veith. If the termination referred to in i) occurs forthwith following a change of control, all of the unvested stock options held by Mr. Veith shall vest immediately and remain exercisable for twelve months (subject to earlier expiration); and

(c) on the occurrence of (a) or (b), if the criteria for earning a milestone bonus set out in his employment agreement are satisfied (whether prior to the date of termination or subsequent to the date of termination but prior to the date by which such criteria were to be met), Mr. Veith shall be entitled to such milestone bonus effective as of the date that the applicable milestones are reached.

The estimated incremental payments to Mr. Veith in the above scenarios are: (a) a lump sum of $300,729, the accelerated vesting and delivery of 114,399 RSUs, valued at $68,837 and accelerated vesting of stock options valued at $nil; and (b) a lump sum of $300,729, the accelerated vesting and delivery of 114,399 RSUs, valued at $68,837 and, assuming termination occurs forthwith following a change of control, accelerated vesting of stock options valued at $nil. In addition to the foregoing payments under each of scenarios (a) and (b) and assuming full satisfaction of all applicable criteria under scenario (c), Mr. Veith would be entitled to a milestone bonus of up to a maximum of $165,401, being 55% of base salary.

Joseph D. Kuhach

Mr. Kuhach's employment contract provides that:

(a) in the case of termination without cause or termination upon disability, the Company must pay twelve months wages in a lump sum, cause all of the unvested stock options that would otherwise have vested during the succeeding twelve months to vest immediately and to remain exercisable for twelve months (subject to earlier expiration), cause all of the unvested RSUs that would otherwise have vested during the succeeding twelve months to vest immediately and deliver those RSUs that have, or are deemed to have, vested to Mr. Kuhach;

(b) in the case of: i) termination of the employment contract by the Company, other than in the case of termination for just cause or disability; or ii) resignation for just cause, in either case, within twelve months of a change of control, the Company must pay twelve months wages in a lump sum, cause all of the vested stock options to remain exercisable for twelve months (subject to earlier expiration) and cause all RSUs, vested or unvested on the date of termination, to be deemed vested and deliverable to Mr. Kuhach. If the termination referred to in i) occurs forthwith following a change of control, all of the unvested stock options held by Mr. Kuhach shall vest immediately and remain exercisable for twelve months (subject to earlier expiration);

(c) on the occurrence of (a) or (b), if the criteria for earning a milestone bonus set out in his employment agreement are satisfied (whether prior to the date of termination or subsequent to the date of termination but prior to the date by which such criteria were to be met), Mr. Kuhach shall be entitled to such milestone bonus effective as of the date that the applicable milestones are reached;

(d) Mr. Kuhach is bound by a non-competition clause effective until the later of twelve months after the termination of active employment or the date he no longer receives compensation of any kind under the employment contract;

(e) Mr. Kuhach is bound by a non-solicitation clause effective for twelve months after the termination of active employment; and

(f) Mr. Kuhach is bound by a confidentiality clause that is effective for three years after the termination of active employment.

The estimated incremental payments to Mr. Kuhach in the above scenarios are: (a) a lump sum of $322,920, the accelerated vesting and delivery of 132,707 RSUs, valued at $79,854 and accelerated vesting of stock options valued at $nil; and (b) a lump sum of $322,920, the accelerated vesting and delivery of 132,707 RSUs, valued at $79,854 and, assuming termination occurs forthwith following a change of control, accelerated vesting of stock options valued at $nil. In addition to the foregoing payments under each of scenarios (a) and (b) and assuming full satisfaction of all applicable criteria under scenario (c), Mr. Kuhach would be entitled to a milestone bonus of up to a maximum of $177,606, being 55% of base salary.

RSU Plan

If a NEO is terminated without cause within six months of a change of control, all of his unvested RSUs shall vest on the earlier of the original vesting date or upon termination.

Name	Value of RSUs Upon Change of Control ($)(1)
Carlos A. Cabrera	104,545
Gerald D. Schiefelbein	71,144
Santiago Pástor Morris	78,581
Edwin J. Veith	68,837
Joseph D. Kuhach	79,854

(1) Calculated as the December 31, 2013, closing market price of the Company's common shares multiplied by the number of unexercised RSUs and converted to US dollars using the December 31, 2013, Bank of Canada closing exchange rate.

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DIRECTOR COMPENSATION

Each non-management director other than Mr. Abboud, the Independent Lead Director, receives $40,000 per annum for acting as a director of the Company. Mr. Abboud, Independent Lead Director, receives $80,000 per annum.

Until May 2012, the fees for acting as chair of board committees were $5,000 per annum for each position other than the Audit Committee chair who received $10,000 per annum. In May 2012, to bring such fees more in line with industry standards, the annual fees for acting as committee chairs were increased to $10,000 per annum other than the audited committee chair whose annual fee was increased to $15,000 per annum.

NON-MANAGEMENT DIRECTOR COMPENSATION TABLE

The following compensation was earned by non-management directors in 2013.

Name	Fees Earned ($)	Option-Based Awards(1) (US$)	Other(2) ($)	Total ($)
A. Robert Abboud	100,000	15,937	10,222	126,159
Howard R. Balloch	70,000	15,937	–	85,937
Brian F. Downey	76,000	15,937	3,313	95,250
Robert G. Graham	52,000	15,937	–	67,937
Peter G. Meredith	47,000	15,937	55,163	118,100
Alexander A. Molyneux	51,000	15,937	–	66,937
Robert A. Pirraglia	67,000	15,937	6,507	89,444