IVANHOE ENERGY INC
Form 10-K
March 15, 2012

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, 2011
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: None
Securities registered pursuant to Section 12(g) 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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. þ Yes o 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, 2011, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $547,464,841 based on the Toronto Stock Exchange closing price on that date. At March 5, 2012, the registrant had 344,139,428 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	mmbls/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$)	2011	2010
Closing	0.98	1.01
High	1.06	1.01
Low	0.94	0.93

Average noon	1.01	0.97

On March 5, 2012, the noon-day exchange rate was US$0.99 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", "bel "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 earnings; 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 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; the expectation of negotiating of an extension to certain of the Company's production sharing agreements; the expectation of the Company's ability to comply with the newly enacted safety and environmental rules; 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 are 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, China, 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, China 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.

AVAILABLE INFORMATION

The principal executive offices of Ivanhoe Energy Inc. ("Ivanhoe," the "Company," "we," "our," or "us") are located at 9 Canada Place, Suite 654, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

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.

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Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the CSA. Further, 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.

PART I

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Ivanhoe is an independent international heavy oil development and production 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, Ecuador, China and Mongolia, 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.

CORPORATE STRATEGY

Ivanhoe continues to pursue its core strategies, which are:

— Utilize long-standing knowledge and relationships in the Far East to pursue conventional oil and gas production and exploration opportunities;

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

— 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.

Pursuing Natural Gas in China

Ivanhoe's wholly-owned subsidiary, Sunwing, has been conducting operations in China since the mid-1990s. In particular, Sunwing is focused on a key natural gas exploration project (the Zitong Block) in Sichuan Province of China. Sichuan is the oldest and one of the most productive gas producing regions of China. Sinopec and PetroChina have made significant gas discoveries in blocks adjacent to Sunwing's Zitong Block.

The Sichuan Basin, located in central China approximately 930 miles southwest of Beijing, is the country's largest gas-producing region, currently producing more than 800 mmcf/d and estimated by Chinese officials to contain a natural gas resource potential of 260 tcf. There is a strong and growing local market for natural gas, with approximately 120 million people living within the basin and with well-developed grid connections to adjacent industrial and population areas.

Natural gas sales are regulated in China and current prices are approximately $5.00/mcf at the wellhead. As part of China's commitment to develop cleaner sources of energy, demand for natural gas is projected to continue to grow in the country and Sunwing's goal is to tap into this burgeoning market.

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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 volatility in oil markets and marked shifts in the demand and supply landscape. Ivanhoe believes that long term demand and the natural decline of conventional oil production will see 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 steam 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, as producers struggle to replace declines in light oil reserves. 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.

With regard to non-conventional heavy oil and bitumen, a dramatic increase in interest and activity has been fuelled by higher prices, in addition to various key advances in technology, including improved remote sensing, horizontal drilling and new thermal techniques. This has enabled producers to more effectively access the extensive heavy oil resources around the world.

These newer technologies, together with higher oil prices, 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 that the producer is faced with when the product gets to market; 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 and lies fallow.

Ivanhoe’s Value Proposition

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

Ivanhoe’s HTL™ upgrading is a partial upgrading process that is designed to operate 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 based on carbon rejection, a tried and tested concept in heavy oil processing. The key advantage of HTL™ is that it is a very fast process, with processing times typically under a few seconds. This results in smaller, less costly facilities and eliminates the need for hydrogen addition, 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.

The economics of a project are effectively dictated by the advantages that HTL™ can bring to a particular opportunity. The more stranded the resource and the fewer monetization alternatives that the resource owner has, the greater the opportunity Ivanhoe will have to establish its unique value proposition.

Implementation Strategy

Ivanhoe is an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and the Company believes it has a competitive advantage because of its patented upgrading process. In addition, because Ivanhoe has experienced thermal recovery teams, 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.

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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.

— Advance its natural gas project in the Zitong Block in Sichuan Province, China. Through its wholly-owned subsidiary, Sunwing Energy, proceed with additional planning and operational analysis to develop an appraisal program leading to a full development plan for the Zitong block.

— 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.

— Build internal capabilities. The Company continues to seek to build its internal leadership and technical capabilities through the addition of key personnel associated with each major project.

— 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 oil and gas operations are located in three geographic areas: Asia, Canada and Ecuador. The Technology Development area captures costs incurred to develop, enhance and identify improvements in the application of the HTL™ technology. Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 19 to the consolidated financial statements and in the MD&A in this Annual Report.

Asia

China

Zitong

In November 2002, we entered into a 30 year production sharing contract ("PSC") with China National Petroleum Corporation ("CNPC") for the Zitong block, which covers an area of approximately 248,000 gross acres after contractual relinquishments in the Sichuan basin. In 2006, we farmed out 10% of our working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan ("MGC") for $4.0 million.

In Phase I of the contract, Ivanhoe reprocessed 1,649 miles of existing 2D seismic data and acquired 705 miles of new 2D seismic data. Two wells were drilled and although both wells encountered expected reservoirs and gas was tested on the second well, neither well demonstrated commercially viable flow rates and both wells were suspended. In Phase II of the contract, the Yixin-2 and Zitong-1 gas wells were drilled in late 2010 and completed in early 2011. Both wells encountered gas in the Xu-4 Formation and were shut-in for pressure build-up following initial flow and pressure tests.

On December 30, 2011, the Company entered into a supplementary agreement to the Contract for Exploration, Development and Production in Zitong Block, Sichuan Basin with CNPC for the Zitong block ("Supplementary Agreement"). The Supplementary Agreement effectively extends the exploration period under the PSC by creating a 36 month evaluation phase beginning July 1, 2011, for the performance of additional work. The Supplementary Agreement is subject to ratification by the Ministry of Commerce of the People's Republic of China.

On January 11, 2012, Ivanhoe signed a binding Memorandum of Understanding which contemplates a transaction (the "Zitong Transaction") whereby Ivanhoe will assign its entire working interest in the Zitong PSC to Shell China Exploration and Production Company Limited ("Shell"). Completion of the Zitong Transaction is subject to government approvals and other prescribed conditions, including rights of first refusal by both CNPC and Ivanhoe's working interest partner, MGC.

Dagang

Ivanhoe's oil production originates in the Kongnan oilfield in Dagang, Hebei Province, China (the "Dagang field"). We have a 30 year PSC with CNPC, covering an area of 10,255 gross acres. From 2000 to 2007, we drilled 46 wells and commercial production commenced on January 1, 2009. The project reached cost recovery in

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September 2009 and our working interest decreased to 49%. Operations in the Dagang field will revert to CNPC at the end of the 20 year production phase of the contract or earlier if the field is abandoned.

In 2011, quotas restricted production to 80,000 gross tonnes or 1,600 bbls/d gross. Actual production in 2011 averaged 967 bbls/d net. The production quota in 2012 remains set at 80,000 gross tonnes.

Mongolia

Through a merger with PanAsian Petroleum Inc. in November 2009, we acquired a PSC for the Nyalga Block XVI in the Khenti and Tov provinces in Mongolia. The block covers an area of approximately 3.1 million gross acres, after a 25% relinquishment in 2010. 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 nominate 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.

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 integrated oil sands project (“Tamarack” or the “Tamarack Project”) is comprised of a two-phased 40,000 bbl/d steam-assisted gravity drainage thermal recovery (“SAGD”) and HTL™ facility. Our independent reserve evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), has assigned total 3P reserves of 219 mmbbls of bitumen to Tamarack. Talisman held a 20% back-in right which expired in July 2011. Additionally, in 2011, Ivanhoe repaid a $40 million promissory note to Talisman that was part of the initial purchase price.

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 in the third quarter of 2011. The Company submitted the supplemental information to the regulators in the fourth quarter of 2011.

As the regulatory process unfolds, Ivanhoe continues to engage and consult with numerous local and aboriginal stakeholders to identify potential project impacts and mitigations and economic and employment opportunities for residents of area communities. It is anticipated that the regulatory approval process will be completed later in 2012. Project advancement, as currently envisaged, is subject to regulatory approval, financing and board sanction.

Ecuador

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a 30 year contract with the Ecuador state oil companies Petroecuador and Petroproduccion. The contract 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 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 Petroproduccion.

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. Later in 2011, the Company completed a 190-kilometre 2-D seismic survey over the southern portion

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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.

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 proved, probable and possible oil reserves as of December 31, 2011:

Summary of Oil and Gas Reserves Using Average 2011 Prices(1)

		China		Canada	Total
(mbbl)	Dagang	Other	Total China	Tamarack	Consolidated
Proved					
Developed	1,146	75	1,221	–	1,221
Undeveloped	421	–	421	–	421
Total proved	1,567	75	1,642	–	1,642
Probable					
Developed	375	–	375	–	375
Undeveloped	447	–	447	175,684	176,131
Total probable	822	–	822	175,684	176,506
Total proved plus probable	2,389	75	2,464	175,684	178,148
Possible					
Developed	–	–	–	–	–
Undeveloped	–	–	–	43,809	43,809

(1) Reserves are the Company's total gross reserves before royalty deductions.

China

Proved Reserves

Proved reserves at December 31, 2011 were 1,729 mbbls. Production during the year was offset by in-field performance improvements from continued water injections and our ongoing hydraulic fracture stimulation program in the Dagang field. Four wells were drilled in 2011, and, in combination with geological review and reservoir mapping, supported additional future drilling locations.

In 2011,153 mbbls were transferred from proved undeveloped to the proved developed category.

Probable Reserves

At December 31, 2011, probable reserves in China were 822 mbbls. Additional probable reserves were assigned based on production improvements and increased recovery factors discussed under proved reserves.

Basis of Reserve Estimates

Reserve estimates were calculated using recovery forecasts based on historical production, supported by volumetric estimates using geological parameters. Recoveries rarely exceed 15% of the volumetrically calculated original oil-in-place per well spacing, which is judged acceptable for a water flood in a light oil reservoir. Improvements in production history and production declines are used for a review of producing reserves. With further mapping and geological reviews, proved and probable undeveloped reserves may then be assigned to future drilling and well optimizations.

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Canada

Probable and Possible Reserves

No additional reserves were assigned to Tamarack in 2011 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.

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 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 CSA, which requires us to disclose reserves and other oil and gas information in accordance with the prescribed standards of NI 51-101 which differ, in certain respects, from SEC requirements. See the Special Note to Canadian Investors on page 11.

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:

— 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.

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 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 29 years of broad petroleum engineering experience in the oil and gas industry in Canada and internationally. His past experience includes reserves estimations for government filings, reservoir development engineering for both oil and gas projects, economic evaluations for potential acquisitions and dispositions, production operations, project management, budgeting and corporate planning.

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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 a 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 companies 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 2011, using the standards contained in SEC Regulations S-X and S-K and Accounting Standards Codification 932 Extractive Activities – Oil and Gas (section 235-55), formerly Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities". Such 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;

— the SEC mandates disclosure of reserves by geographic area only, whereas NI 51-101 requires disclosure of more reserve categories and product types; 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.

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Production, Sales Prices and Production Costs

	2011	2010
Oil production (bbls/d)	967	788
Average sales price ($/bbl)	105.93	75.52
Average operating costs (1) ($/bbl)	44.10	33.05

(1) 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 originates in Asia, specifically the Dagang and Daqing fields in China. The majority of our production comes from Dagang and is sold to the Chinese national petroleum company.

Drilling Activity

	Net Exploratory			Net Development			Total
(net wells)(1)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total Wells Drilled
Asia							
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.

Wells in Progress

At December 31, 2011, we were not actively drilling any wells.

Producing Oil Wells

The Company does not have any producing gas wells. The Company had 49.0 gross (24.0 net) productive oil wells in Asia, as at December 31, 2011.

Acreage

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Asia – China(2)	1,724	845	253,496	225,683
Asia – Mongolia	–	–	3,107,907	3,107,907
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.

(2)

The number of developed acres disclosed in respect of our China properties relates only to those portions of the field covered by our producing operations and does not include the remaining portions of the field previously developed by CNPC.

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.

We signed a specific services contract with the state oil companies of Ecuador in October 2008 that allows us to develop 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 State and in conformity with local laws.

Subsequent to the completion of Phase II of the Zitong PSC, acreage not identified for development and future production was relinquished to CNPC in 2011. The remaining Zitong acreage will be relinquished upon termination of the PSC in 2032.

Under the terms of the Dagang PSC, acreage in the Dagang field will revert to CNPC upon contract termination in 2027, at the latest, unless Ivanhoe abandons the field before then.

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

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 five granted US patents and currently has six US patent applications pending. In other countries, the Company has 11 patents granted and 41 patents are pending. In addition, Ivanhoe owns exclusive, irrevocable licenses to 21 global patents for the rapid thermal processing process as it pertains to petroleum. The expiration date for Ivanhoe's key patents is 2028.

Ivanhoe has a feedstock test facility ("FTF") at the Southwest Research Institute in San Antonio, Texas. The FTF is a small 10-15 bbls/d, highly flexible, state-of-the-art facility which will permit analysis of crude oil in small volumes. 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.

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, reductions in emissions to the air from our operations and result in increased capital expenditures.

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 regulatory process is expected to conclude near the end of 2012. In addition, 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.

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China, Mongolia and Ecuador continue to develop and implement more stringent environmental protection regulations and standards for different industries. 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 Chinese and Mongolian governments regulate various aspects of foreign company operations in their respective countries. Such laws and regulations have generally become more stringent in recent years in Canada, Ecuador, China and Mongolia, 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, 2011, we had 212 employees actively engaged in the business. None of our employees are unionized.

ITEM 1A: RISK FACTORS

Our operations 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 operations. Certain risks set out below constitute "forward-looking statements" and readers should refer to the "Special Note Regarding Forward-Looking Statements" on page 4.

Our ability to continue as a going concern may be adversely affected by inadequate funding

We have a history of operating losses and cash flow from operating activities will not be sufficient to meet our current obligations and fund future capital projects. Historically, we have relied upon equity capital as our principal source of funding. The operation of our business is dependent upon our ability to obtain additional capital to preserve our interests in current projects and to meet obligations associated with future projects. We may seek financing from a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or