IVANHOE ENERGY INC
Form 10-K
March 17, 2008

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

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2007**
	OR
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

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** *(I.R.S. Employer Identification No.)*
654-999 Canada Place **Vancouver, British Columbia, Canada** *(Address of principal executive offices)*	**V6C 3E1** *(Zip Code)*

(604) 688-8323
(Registrant s telephone number, including area code)
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 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. 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 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. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	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, 2007, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $468,246,525 based on the average bid and asked price as reported on the National Association of Securities Dealers Automated Quotation System National Market System.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at March 10, 2008**
Common Shares, no par value	244,873,349 shares

DOCUMENTS INCORPORATED BY REFERENCE
None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to **dollars** or to **$** are to U.S. dollars and all references to **Cdn.$** are to Canadian dollars. The closing, low, high and average noon buying rates in New York for cable transfers for the conversion of Canadian dollars into U.S. dollars for each of the five years ended December 31 as reported by the Federal Reserve Bank of New York were as follows:

	2007	**2006**	**2005**	**2004**	**2003**
Closing	$ 1.01	$ 0.86	$ 0.86	$ 0.83	$ 0.77
Low	$ 0.84	$ 0.85	$ 0.79	$ 0.72	$ 0.63
High	$ 1.09	$ 0.91	$ 0.87	$ 0.85	$ 0.77
Average Noon	$ 0.94	$ 0.88	$ 0.83	$ 0.77	$ 0.71

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of U.S. dollars into Canadian dollars on February 29, 2008 was $1.02 ($1.00 = Cdn.$0.98).

ABBREVIATIONS

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

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Mboe	= thousands of barrels of oil equivalent
Bopd	= barrels of oil per day
Bbls/d	= barrels per day
Boe/d	= barrels of oil equivalent per day
Mboe/d	= thousands of barrels of oil equivalent per day
MBbls/d	= thousand barrels per day
MMBls/d	= million barrels per day
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day

When we refer to oil in **equivalents** , we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized industry standard in which one Bbl is equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue, losses and negative cash flow from our current exploration and development activities in the U.S. and China; our limited cash resources and consequent need for additional financing; our ability to raise additional financing; uncertainties regarding the potential success of heavy-to-light oil upgrading and gas-to-liquids technologies; uncertainties regarding the potential success of our oil and gas exploration and development properties in the U.S. and China; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of what appear to be promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as may , expect , intend , estimate , anticipate , believe or continue or the negative thereof or variations thereon or similar terminolo We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

AVAILABLE INFORMATION

Copies of our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on or through our website at http://www.ivanhoe-energy.com/ or through the United States Securities and Exchange Commission s website at http://www.sec.gov/.

ITEMS 1 AND 2 ***BUSINESS AND PROPERTIES***

GENERAL

Ivanhoe Energy Inc. (**Ivanhoe Energy** or **Ivanhoe**) is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserve base and production.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

We were 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, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our principal executive office is located at Suite 654 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9. Our headquarters for operations are located at Suite 400 5060 California Avenue, Bakersfield, California, 93309.

CORPORATE STRATEGY

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

The global oil and gas industry is operating near capacity, driven by sharp increases in demand from developing economies and the declining availability of replacement low cost reserves. This has resulted in a significant increase in the relative price of oil and marked shifts in the demand and supply landscape. These shifts include demand moving toward China and India, while supply has shifted towards the need to develop higher cost/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 we focus on the non-conventional heavy oil, both play an important role in Ivanhoe s corporate strategy.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most 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 oil production has been getting heavier. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy-light price differentials have widened significantly.

With regard to non-conventional heavy oil and bitumen, the dramatic increase in interest and activity has been fueled 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 much more effectively access the extensive, heavy oil resources around the world.

These newer technologies, together with firm oil prices, have generated increased access to heavy oil resources, although for profitable exploitation, key challenges remain, with varied weightings, project by project: 1) the requirement for steam and electricity to help extract heavy oil, 2) the need for diluent to move the oil once it is at the surface, 3) the wide heavy-light price differentials that the producer is faced with when the product gets to market, and 4) conventional upgrading technologies 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

Ivanhoe s application of its patented rapid thermal processing process (**RTPtm Process**) for heavy oil upgrading (**HTLtm Technology** or **HTLtm**) seeks to address the four key heavy oil development challenges outlined above, and can do so at a relatively small minimum economic scale.

Ivanhoe s HTLtm upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000-30,000 barrels per day. This is substantially smaller than the minimum economic scale for conventional stand-alone upgraders such as delayed cokers, which typically operate at scales of well over 100,000 barrels per day. Ivanhoe s HTLtm Technology is based on carbon rejection, a tried and tested concept in heavy oil processing. The key advantage of HTLtm is that it is a very fast process processing times are typically under a few seconds. This results in smaller, less costly facilities, and in addition eliminates the need for hydrogen addition, an expensive, large minimum scale step typically required in conventional upgrading. In addition, Ivanhoe s HTLtm Technology has the added advantage of converting upgrading byproducts into onsite energy, as opposed to the generation of large volumes of low value coke.

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

1. Virtual elimination of external energy requirements for steam generation and/or power for upstream operations.

2. Elimination of the need for diluent or blend oils for transport.

3. Capture of the majority of the heavy-light oil value differential.

4. Relatively small minimum economic scale of operations suited for field upgrading and for smaller field developments.

The business opportunities available to Ivanhoe correspond to the challenges each potential heavy oil project faces. In Canada, Ecuador, California, Iraq, and Oman all four of the HTLtm advantages identified above come into play. In others, including certain identified opportunities in Colombia and Libya, the heavy oil naturally flows to the surface, but transport is the key problem.

The economics of a project are effectively dictated by the advantages that HTL[tm] 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 the Company will have to establish the Ivanhoe value proposition.

Implementation Strategy

We are an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today. Because we have a unique resource in our patented technology and because we have experienced people who have developed oil fields in the past and are involved in acquiring new resources, we are in a position to work with partners on stranded heavy oil resources around the world to add value to these resources.

In 2007 Ivanhoe completed the HTL^{tm} equipment and process testing associated with the Commercial Demonstration Facility in California. Following this work, Ivanhoe s principal focus has shifted to full scale commercial deployment of HTL^{tm} facilities. This effort includes the pursuit of opportunities in Canada and elsewhere related to the deployment of full-scale commercial HTL^{tm} facilities in business arrangements that would provide Ivanhoe with a share of reserves and production of heavy oil. In addition, in certain industrial and geographic markets, Ivanhoe is pursuing opportunities where shareholder value can be generated through commercial deployment of HTL^{tm} in business arrangements that may not include the generation of reserves and production for Ivanhoe.

The Company s implementation strategy includes the following:

1. ***Build a portfolio of major HTL^{tm} projects.*** We will continue to deploy our personnel and our financial resources in support of our goal to capture opportunities for development projects utilizing our HTL^{tm} Technology.

2. ***Advance the technology.*** Additional development work will continue as we advance the technology through the first commercial application and beyond.

3. ***Enhance our financial position in anticipation of major projects.*** Implementation of large projects requires significant capital outlays. We are refining our financing plans and establishing the relationships required for the development activities that we see ahead.

4. ***Build internal capabilities in advance of major projects.*** The HTL^{tm} technical team, which includes our own staff, specialized consultants including the inventors of the technology, and our enhanced oil recovery (**EOR**) team will be supplemented and expanded to add additional expertise in areas such as project management.

5. ***Build the relationships that we will need for the future.*** Commercialization of our technologies demands close alignment with partners, suppliers, host governments and financiers.

In order to facilitate the implementation of our business strategy, we plan to undertake a reorganization of our corporate, business and governance structures. We will create two new geographically focused business units that will pursue project opportunities in Latin America and the Middle East/North Africa (**MENA**), respectively. These new business units will operate through separate subsidiary companies in much the same way as our China business unit is operated through Sunwing Energy Ltd **(** **Sunwing**) our wholly owned subsidiary. Like Sunwing, our new Latin America and MENA business units will each have its own board of directors and senior management team. Initially, the Latin America and MENA subsidiaries and Sunwing will remain wholly-owned, and will be funded, by Ivanhoe Energy. It is intended that each subsidiary will eventually become financially independent and, as their respective geographically focused business strategies unfold, that each subsidiary will seek and obtain external sources of capital from third parties that will effectively reduce Ivanhoe Energy s ownership interest.

Ivanhoe Energy itself will retain ownership of the HTL^{tm} Technology and will concentrate its business development efforts on project opportunities in North America, with a particular focus on Canada. Our Latin America business unit will continue the pursuit of opportunities to apply the HTL^{tm} Technology to heavy oil projects in Ecuador, Mexico and elsewhere in Latin America. Our MENA business unit will focus on heavy oil project opportunities in the Middle

East/North Africa region, with a particular focus on Iraq, Egypt and Libya. It will also be responsible for advancing our GTL project opportunity in Egypt. Sunwing will continue to operate our existing EOR and exploration projects in China and to pursue business development initiatives in the East Asia region. Each of our Latin America, MENA and East Asia business units will have the exclusive right within its own defined geographical region to obtain from Ivanhoe Energy a project-specific site license of the HTL^tm Technology as and when the decision is made to develop an HTL^tm project.

In order to more effectively utilize the extensive geographically specific experience and expertise of our existing senior management personnel and board of directors, certain Ivanhoe Energy executive officers will be re-assigned to senior management positions within the Latin America and MENA business units and a number of incumbent directors will leave the Ivanhoe Energy board of directors and become directors of one or more of our Latin America, MENA and Sunwing subsidiaries. Our Deputy Chairman, Robert M. Friedland will serve as Executive Chairman and Chief Executive Officer. Our current President and Chief Executive Officer, Joseph I. Gasca has elected not to stand for re-election as a board member, and will step down as President and Chief Executive Officer as of May 29, 2008. Until then, he will continue to serve as President and Chief Executive Officer. It is expected that these changes to the Ivanhoe Energy board of directors and senior management will take effect immediately following our annual general meeting of shareholders which is scheduled to be held on May 29, 2008. See Item 10 Directors, Executive Officers and Corporate Governance . In anticipation of his appointment as our Chief Executive Officer, Mr. Friedland was awarded 2.5 million incentive stock options and we agreed to share part of the costs of operating an aircraft owned by Mr. Friedland. See ITEM 11. EXECUTIVE COMPENSATION AND ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

HEAVY TO LIGHT OIL UPGRADING TECHNOLOGY

RTP^{tm} License and Patents

In April 2005, we acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) whereby we acquired an exclusive, irrevocable license to Ensyn s RTP^{tm} Process for all applications other than biomass. In January 2007 the Company received a Notice of Allowance from the U.S. Patent Office for the first of a family of additional petroleum upgrading patent applications. Since Ivanhoe acquired the patented heavy oil upgrading technology it has been working to expand patent coverage to protect innovations to the HTL^{tm} Technology as they are developed. This allowance is the first patent protection that has been granted directly to Ivanhoe Energy, and significantly broadens the Company s portfolio of HTL^{tm} intellectual property for petroleum upgrading and opens up additional HTL^{tm} patenting opportunities for Ivanhoe Energy. In addition, Ivanhoe Energy currently has several additional HTL^{tm} patents in various stages of prosecution.

Commercial Demonstration Facility

In 2004, Ensyn constructed a Commercial Demonstration Facility (**CDF**) to confirm earlier pilot test results on a larger scale and to test certain processing options. This facility, that the Company acquired as part of the Ensyn merger was built in the Belridge field, a large heavy oil field owned by Aera Energy LLC (**Aera**), a company owned by affiliates of ExxonMobil and Shell. In March 2005, initial performance testing of the CDF was completed successfully and the results of the test were verified by two large independent engineering consulting firms. The CDF demonstrated an overall processing capacity of approximately 1,000 barrels-per-day of raw, heavy oil from the Belridge California heavy oil fields and a hot section capacity of 300 barrels-per-day.

During 2007, technical developments were led by two important test runs at the CDF: a High Quality configuration was demonstrated on California vacuum tower bottoms (**VTBs**) and a key test was successfully completed processing Athabasca bitumen pursuant to a longstanding technology development agreement with ConocoPhillips Canada Resources Corp. These two key tests are the capstones of the CDF test program and we have now fulfilled the primary technical objectives of the CDF. The goals of the test program were: (1) to confirm the key processing results generated in the over 90 pilot plant runs of heavy oil and bitumen from Athabasca and the U.S. in a large facility, and (2) to provide sufficient data for the design and construction of full-scale, commercial HTL^{tm} plants.

The Athabasca bitumen test provided important technical information related to the design of full-scale HTL^{tm} facilities. This test, and other test run data, correlated the performance of the CDF with earlier runs on the smaller scale pilot facility, and validated the assumptions in Ivanhoe Energy s economic models.

Feedstock Test Facility

The Company has initiated the construction of an additional HTL^{tm} facility, the Feedstock Test Facility (**FTF**). The FTF is a small (15-20 Bbls/d), highly flexible state-of-the-art HTL^{tm} facility which will permit more cost-effective screening of feedstock crudes for current and potential partners in smaller volumes and at lower costs than required at the CDF. As we continue to advance our technology, this unit will form an integral part of the ongoing post-commercialization optimization of our products and processes. The FTF will provide additional data and will support the detailed engineering process once the first commercial target location and crude has been established.

This facility, costing approximately $7.9 million, is expected to be completed in mid 2008, and be commissioned soon thereafter. The FTF will be located in San Antonio, Texas.

HTL^{tm} Business Development

We are pursuing HTL^{tm} business development opportunities around the world, primarily Western Canada, Latin America and the Middle East/North Africa region. Integrated HTL^{tm}/Steam Assisted Gravity Drainage (**SAGD**) financial models for Athabasca have been updated and refined, incorporating newly revised capital costs from AMEC, and revised price assumptions and currency exchange rate changes. These updated models show that HTL^{tm} integration represents robust value-add for thermal bitumen projects in Western Canada.

We also made significant progress in developing an execution plan with AMEC, our Tier One engineering contractor, for the design and construction of full-scale commercial HTL^{tm} facilities. The Company is proceeding with preliminary, non site-specific engineering related to the first fully commercial HTL^{tm} facility, supported by the recent successful CDF runs.

In October 2004, we signed an MOU with the Ministry of Oil of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field s reservoirs contain a large proven accumulation of 17.1° API heavy oil at a depth of about 1,000 feet. We have completed the reservoir assessment and have evaluated various recovery methods. Facility design work as well as an economic evaluation are complete. Based on this evaluation we submitted a technical proposal to the Iraq Ministry of Oil who have accepted and approved the study and its conclusions.

In the first half of 2007, the Company and INPEX Corporation (**INPEX**), Japan s largest oil and gas exploration and production company, signed an agreement to jointly pursue the opportunity to develop the above noted heavy oil field in Iraq. During the second quarter of 2007, INPEX paid $9.0 million to the Company as a contribution towards the Company s past costs related to the project and certain costs related to the development of its HTL^{tm} upgrading technology.

The agreement provides INPEX with a significant minority interest in the venture, with Ivanhoe Energy retaining a majority interest. Both parties will participate in the pursuit of the opportunity but Ivanhoe will lead the discussions with the Iraqi Ministry of Oil. Should the Company and INPEX proceed with the development and deploy Ivanhoe Energy s HTL^{tm} Technology, certain technology fees would be payable to the Company by INPEX.

In September 2007, the Ministry of Oil requested that we submit a commercial proposal for a 30,000 Bopd Pilot Project to test the reservoir response to thermal recovery methods, optimize the development plan and build/operate the first HTL^{tm} unit for the field. We expect to be negotiating an agreement during the first half of 2008.

GAS-TO-LIQUIDS TECHNOLOGY

Syntroleum License

We own a non-exclusive master license entitling us to use Syntroleum Corporation s (**Syntroleum**) proprietary technology (**GTL Technology** or **GTL**) to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products in an unlimited number of projects with no limit on production volume. Syntroleum s proprietary

GTL process is designed to catalytically convert natural gas into synthetic liquid hydrocarbons. This patented process uses compressed air, steam and natural gas as initial components to the catalyst process. As a result, this process (the **Syntroleum Process**[tm]) substantially reduces the capital and operating costs and the minimum economic size of a GTL plant as compared to the other oxygen-based GTL technologies. Competitor GTL processes use either steam reforming or a combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for oxidation are expensive and considered hazardous and increase operating costs.

The attraction of the GTL Technology lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but is considered to be stranded based on the relative size of the fields and their remoteness from comparable sized markets. We have performed detailed project feasibility studies for the construction, operation and cost of plants from 47,000 to 185,000 Bbls/d. Additionally, we have conducted marketing and transportation feasibility studies for both European and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL diesel and GTL naphtha.

GTL Business Development

At the present time, the only GTL project we are pursuing is the Egyptian GTL project described herein. In 2005, we signed a memorandum of understanding with Egyptian Natural Gas Holding Company (**EGAS**), the state organization responsible for managing Egypt s natural gas resources, to prepare a feasibility study to construct and operate a GTL plant that would convert natural gas to ultra-clean liquid fuels in Egypt. We completed an engineering design of a GTL plant to incorporate the latest advances in Syntroleum GTL technology and have completed market and pricing analysis for GTL products to reflect changes since the original evaluation was completed several years ago. Plant capacity options of 47,000 and 94,000 Bbls/d were evaluated and in May 2006, we presented the feasibility study report to EGAS along with three commercial proposals. Based on EGAS review, and response to the proposals, we submitted a revised proposal in October 2006. In November 2006 the Company signed a Participation Agreement with H.K. Renewable Energy Ltd. (**HKRE**). In August 2007, we signed a Term Sheet with EGAS (a 24% project participant) and HKRE (a 15% project participant) which set out the commercial terms for a 47,000 Bbls/d project to be run on a tolling basis. EGAS agreed to commit, at no cost to the project, up to 4.2 trillion cubic feet of natural gas, or approximately 600 MMcf/d for the anticipated 20-year operating life of the project, subject to satisfactory conclusion of pre-front end engineering and design (**FEED**) confirming commercial viability and financing ability, the negotiation and signature of a definitive agreement and approval by the Company s Board of Directors and the appropriate authorities in Egypt.

OIL AND GAS PROPERTIES

Our principal oil and gas properties are located in California s San Joaquin Basin and Sacramento Basin, the Permian Basin in Texas and the Hebei and Sichuan Provinces in China. Set forth below is a description of these properties.

The following table sets forth the estimated quantities of proved reserves and production attributable to our properties:

Property	Location	2007 Production (In MBoe)	Percentage of Total 2007 Production	12/31/2007 Proved Reserves (In MBoe)	Percentage of Total Estimated Proved Reserves
South Midway	Kern County, California	178	26%	982	40%
West Texas	Midland County, Texas	20	3%	208	8%
Other	California	2	0%		0%
Total U.S.		199	29%	1,191	48%

Dagang	Hebei Province, China	464	68%	1,195	48%
Other	China	19	3%	85	4%
Total China		483	71%	1,280	52%
Total		682	100%	2,471	100%

Note: See the Supplementary Disclosures About Oil and Gas Production Activities , which follow the notes to our consolidated financial statements set forth in Item 8 in this Annual Report on Form 10-K, for certain details regarding the Company s oil and gas proved reserves, the estimation process and production by country. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and GLJ Petroleum Consultants Ltd., respectively. We have not filed with nor included in reports to any other U.S. federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Special Note to Canadian Investors

Ivanhoe is a United States Securities and Exchange Commission (**SEC**) registrant and files annual reports on Form 10-K. Accordingly, our reserves estimates and securities regulatory disclosures are prepared based on SEC disclosure requirements. In 2003, certain Canadian securities regulatory authorities adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (**NI 51-101**) which prescribes certain standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information. We applied for, and have been granted, exemptions from certain NI 51-101 disclosure requirements. These exemptions permit us to substitute disclosures based on SEC requirements for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the **COGE Handbook**) modified to reflect SEC requirements.

The reserves quantities disclosed in this Annual Report on Form 10-K represent net proved reserves calculated on a constant price basis using the standards contained in SEC Regulation S-X and 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 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 U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;

- the SEC mandates disclosure of proved reserves the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein* calculated using year-end constant prices and 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 proved and proved developed reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;

- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs; 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 and to file their reports.

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 requirements and NI 51-101 may be material.

United States

Production and Development

South Midway

We currently have 60 producing wells in South Midway and are the operator, with a working interest of 100% and a 93% net revenue interest. In 2006, we drilled ten new wells on the South Midway properties compared to 2005 when we drilled one development well, two temperature observation wells and one exploratory well. Three wells in this program were drilled to test for pool extensions or new pool discoveries. Two extensions were found which have led to more development work and potential reserves. The Company purchased an additional steam generator in 2007 and during the interim while this generator was being retro fitted we had lower than predicted steam injection rates. Downtime during the second quarter to repair our existing steam generator further hindered the steam operations. The Company delayed the drilling of new wells in 2007 until the new generator was available. The new generator was put in full time service in September 2007 and we began the preparation for drilling new wells in the fourth quarter of 2007. In 2007 we produced an average 487 net Bopd (534 gross Bopd), with current production approximately 496 net Bopd (517 gross Bopd) compared to 543 net Bopd (590 gross Bopd) at December 31, 2006. An eight well drilling program is currently underway. The production results from this program will begin to be realized in the first quarter of 2008.

West Texas

In 2000, we farmed into the Spraberry property, which is a producing property located on 2,500 gross acres in the Spraberry Trend of the Permian Basin in West Texas. We retain working interests ranging from 31% to 48% in 25 wells, which are currently producing approximately 53 net Boe/d compared to 80 net Boe/d at December 31, 2006. The future decline of the oil and gas production rates are expected to be moderate and should lead to consistent performance and long life reserves.

Other

In mid-2004, we farmed into the McCloud River prospect near the Cymric field in the San Joaquin Basin. We have a 24% working interest in this 880 gross-acre prospect. The initial well resulted in a dry hole. In 2005, a second prospect, North Salt Creek #1, was drilled to 2,500 feet on the acreage and was a discovery, encountering multiple oil and gas bearing horizons. North Salt Creek #1 commenced natural gas sales in September 2005 at a rate of 1,000 Mcf/day. Production was subsequently suspended as the natural gas was intended to be used as fuel in a steam operation. Drilling of two follow-up wells was completed in the fourth quarter of 2005. Multiple targets were encountered in both of these wells. One of the intervals is in a diatomite formation which has large oil storage capacity, but contains heavy oil that requires steam stimulation for extraction. Each of these wells was steamed in 2006, the results of which were sub economic. A fourth well was drilled in 2007. More steam stimulation of this diatomite interval occurred in the fourth quarter of 2007, the evaluation of these tests is underway and should lead to more development.

In the first quarter of 2006, we sold our working interest in our three producing wells in the Citrus prospect for $5.4 million. We still hold 2,316 net acreage in this prospect, all of which has been farmed out. As part of this farm out the Company retained a carried 35% working interest in the property. The operator drilled one well to 9,500 feet, abandoned the well and then withdrew from the farm out agreement. The Company has since farmed out the Citrus leases to another company under which we will get a 5% royalty before payout and a 10% royalty after payout on any wells drilled in the prospect leases.

Exploration

The Company is focusing its exploration efforts on the lower risk opportunities noted below.

Knights Landing

In 2004, we farmed in to the Knights Landing project, which is a 15,700 gross-acre block located in the Sacramento Gas Basin in northern California. We drilled nine new exploratory wells which resulted in three successful completions and six dry holes. Subsequent to this drilling program we increased our working interests in the project and 11 existing producing natural gas wells. By the end of 2005, production from the Knights Landing wells had been fully depleted in all but one well, which was producing at minimal levels. This well was full depleted by the end of 2006.

In late 2005, we acquired a 3-D seismic data program over 25 square miles covering our Knights Landing acreage block. We completed our seismic acquisition program in December 2005 and completed processing and interpretation of the seismic data in 2006. In the first quarter of 2008, negotiations were underway with a third party to farm out a 50% working interest in the Knights landing properties in return for a 10 well drilling obligation to be drilled in the second quarter of 2008. The primary objective of this development and exploration program is the

Starkey Sand formation, which is an established producing reservoir in the region that lies between depths of 2,000 to 3,500 feet.

Aera Exploration Agreement

The Aera exploration agreement, originally covering an area of more than 250,000 acres in the San Joaquin Basin, gave us access to all of Aera s exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects. We identified 13 prospects within 11 areas of mutual interest (**AMI**) covering approximately 46,800 gross acres owned by Aera and an additional 24,200 acres of leased mineral rights. Of the 13 prospects submitted, Aera has elected to take a working interest in 10 prospects, resulting in our retention of working interests ranging from 12.5% to 50%. We have a 100% working interest in three prospects in which Aera elected not to participate South Midway, Citrus and North Yowlumne. We will continue to hold exploration rights to the lands within each previously designated and accepted prospect until an exploration well is drilled on that prospect. There is no time deadline for drilling to occur if Aera elects to participate in the drilling of a prospect. If Aera elects not to participate we have an additional two years to drill the prospect on our own or with other parties. This two-year period will be extended as long as we continue to drill or have established production.

Other

In December 2005, drilling commenced on the North Yowlumne prospect with a planned total depth of 13,000 feet to test the Stevens sands that have produced over 100 million barrels of oil at the nearby Yowlumne field. The well did not produce commercial quantities of hydrocarbons during several tests and has been suspended indefinitely by the operator. In March 2007, the Company assigned its rights to this property for $1.0 million and retained a carried 15% working interest in future drilling of the prospect. A second well was drilled on the prospect in late 2007 which is now being tested.

China

Production and Development

Our producing property in China is a 30-year production-sharing contract with China National Petroleum Corporation (**CNPC**), covering an area of 10,255 gross acres divided into three blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the **Dagang field**). Under the contract, as operator, we fund 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery, at which time our entitlement reverts to 49%. Our entire interest in the Dagang field will revert to CNPC at the end of the 20-year production phase of the contract or if we abandon the field earlier.

In January 2004, we negotiated farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**) a subsidiary of China International Trust and Investment Corporation (**CITIC**) whereby Richfirst paid $20.0 million to acquire a 40% working interest in the field after Chinese regulatory approvals, which were obtained in June 2004. The farm-out agreement provided Richfirst with the right to convert its working interest in the Dagang field into common shares in the Company at any time prior to eighteen months after closing the farm-out agreement. Richfirst elected to convert its 40% working interest in the Dagang field and in February 2006 we re-acquired Richfirst s 40% working interest.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of our Overall Development Plan (**ODP**) to the Chinese regulatory authorities for approval. Final government approval was obtained in April 2003, after which the development phase commenced in late 2003. We suspended drilling in late 2005 to allow for detailed evaluation of well productivity and production decline performance. By the end of 2006, we had drilled a total of 39 development wells, as compared to the estimated 115 wells set out in the approved ODP, and in the fourth quarter of 2006, we reached agreement with CNPC to reduce the overall scope of the ODP to approximately 44 wells through a modified ODP. This program included a further five development wells to be drilled in 2007. This program has been finalized and all five wells have been completed and placed on production. It is expected that commercial production will be declared in the fourth quarter of 2008 following conversion of an additional two wells to water injection for pressure maintenance.

We drilled the five new development wells in 2007 as compared to 2006 when we completed one well drilled in 2005, fracture stimulated 12 wells and re-completed 13 wells. Only a third of the net pay in each of the new five wells was completed and fracture stimulated in 2007. The remaining pay will be completed later. Due to the net pay being spread over hundreds of meters vertical depth, it is more effective to complete and fracture the productive intervals in stages. In addition, we have now relinquished three of the six blocks that were part of the ODP. The year-end 2007 gross production rate was 1,900 Bopd (290 Bopd resulting from the five new wells) compared to 1,877 Bopd at the end of 2006 and 2,310 Bopd at the end of 2005. We currently sell our crude oil at a three-month rolling average price of Cinta crude which historically averages approximately $3.00 per barrel less than West Texas Intermediate (**WTI**) price.

Exploration

In November 2002, we received final Chinese regulatory approval for a 30-year production-sharing contract (the **Zitong Contract**), with CNPC for the Zitong block, which covers an area of approximately 900,000 acres in the Sichuan basin. Under the Zitong Contract, we agreed to conduct an exploration program on the Zitong block consisting of two phases, each three years in length. The first three-year period was ultimately extended to December 31, 2007. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to a maximum of the lesser of 30 years following the date of the Zitong Contract or 20 years of continuous production. In 2006, we farmed-out 10% of our working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million.

The Company now has completed the first phase under the Zitong Contract (**Phase 1**). This included reprocessing approximately 1,649 miles of existing 2D seismic data and acquiring approximately 705 miles of new 2D seismic data, and interpreting this data. This was followed by drilling two wells, totaling an aggregate of 22,293 feet. Both wells encountered expected reservoirs and gas was tested on the second well, but neither well demonstrated commercially viable flow rates and both have been suspended. The Company may elect to reenter these wells to stimulate or drill directionally in the future. In December 2007, the Company and Mitsubishi (the **Zitong Partners**) made a decision to enter into the next three-year exploration phase (**Phase 2**).

By electing to participate in Phase 2 the Zitong Partners must relinquish 30%, plus or minus 5%, of the Zitong block acreage and complete a minimum work program involving approximately 23,700 feet of drilling (including a Phase 1 shortfall), with estimated minimum expenditures for this program of $25.0 million. The Phase 2 seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. The Zitong Partners plan to acquire additional seismic data in Phase 2. The partners have applied to CNPC to offset this additional seismic against the drilling commitment, reducing the required Phase 2 drilling footage requirement. The Zitong Partners plan to acquire the new seismic lines in 2008, commence drilling late in 2009 and complete drilling, completion and evaluation of this prospect in late 2010. The Zitong Partners must complete the minimum work program or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production. In the event of a discovery, the Zitong Partners believe it would be possible to negotiate to enter a Phase III and reduce the amount of land relinquishment to allow further exploration activities.

EMPLOYEES

As at December 31, 2007, we had 145 employees and consultants actively engaged in the business. None of our employees are unionized.

PRODUCTION, WELLS AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities, which follows the notes to our consolidated financial statements set forth in Item 8 in this Annual Report on Form 10-K, for information with respect to our oil and gas producing activities.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average operating costs per unit of production based on our net interest after royalties. Average operating costs are for lifting costs only and exclude depletion and depreciation, income taxes, interest, selling and administrative expenses.

	Average Sales Price			**Average Operating Costs**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Crude Oil and Natural Gas ($/Boe)						
U.S.	$ 61.71	$ 54.86	$ 44.01	$ 21.72	$ 19.54	$ 15.64
China	$ 64.86	$ 62.04	$ 49.97	$ 26.88	$ 20.58	$ 8.27

The following table sets forth the number of commercially productive wells (both producing wells and wells capable of production) in which we held a working interest at the end of each of the last three fiscal years. Gross wells are the total number of wells in which a working interest is owned and net wells are the sum of fractional working interests owned in gross wells.

	2007				**2006**				**2005**			
	Oil Wells		**Gas Wells**		**Oil Wells**		**Gas Wells**		**Oil Wells**		**Gas Wells**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
U.S.	92	74.9	1	0.2	89	73.5	2	1.0	87	69.3	3	1.5
China	44	36.1			42	34.4(1)			43	21.2		

(1) After giving effect to the 40% farm-in/out of Richfirst to the Dagang field.

The following two tables set forth, for each of the last three fiscal years, our participation in the completed drilling of net oil and gas wells:

Exploratory

	Productive Wells						**Dry Wells**					
	2007		**2006**		**2005**		**2007**		**2006**		**2005**	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
U.S.					1.5	0.2			0.6(1)			1.8(2)
China								0.9				1.0
Total					1.5	0.2		0.9	0.6			2.8

(1) Includes 0.6 (1 gross) net exploratory wells drilled during 2005 which were determined to be dry in 2006.

(2) Includes 0.8 net (2 gross) exploratory wells drilled during 2001, which were determined to be dry in 2005.

Development

	Productive Wells						Dry Wells					
	2007		2006		2005		2007		2006		2005	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
U.S.	1.2		9.0		1.0							
China	4.1				10.8							
Total	5.3		9.0		11.8							

Wells in Progress

At the end of 2007, 2006 and 2005 we had 4.3 (5 gross), 5.3 (6 gross) and 1.1 (3 gross) net wells, respectively, which were either in the process of drilling or suspended.

Acreage

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2007. Gross acres include the interest of others and net acres exclude the interests of others:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
U.S.	8,051	3,826	81,010	20,318
China(1)	3,169	2,599	886,869	794,252

(1) 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.

ITEM 1A. ***RISK FACTORS***

We are subject to a number of risks due to the nature of the industry in which we operate, our reliance on strategies which include technologies that have not been proved on a commercial scale, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We may not be able to meet our substantial capital requirements.

Our business is capital intensive and the advancement of either our HTL^{tm} or GTL project development initiatives will require significant investments in property acquisitions and development activities. Since our revenues from existing operations are insufficient to fund the capital expenditures that will be required to implement our HTL^{tm} and GTL project development initiatives, we will need to rely on external sources of financing to meet our capital requirements. We have, in the past, relied upon equity capital as our principal source of funding. We may seek to obtain the future funding we will need through debt and equity markets, through project participation arrangements with third parties or from the sale of existing assets, but we cannot assure you that we will be able to obtain additional funding when it is required and whether it will be available on commercially acceptable terms. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable project acquisition and development opportunities or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

We might not successfully commercialize our technology, and commercial-scale HTL^{tm} and GTL plants based on our technology may never be successfully constructed or operated.

No commercial-scale HTL^{tm} or GTL plant based on our technology has been constructed to date and we may never succeed in doing so. Other developers of competing heavy oil upgrading and gas-to-liquids technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage. Success in commercializing our HTL^{tm} and GTL technologies depends on our ability to economically design, construct and operate commercial-scale plants and a variety of factors, many of which are outside our control. We currently have insufficient resources to manage the financing, design, construction or operation of commercial-scale HTL^{tm} or GTL plants, and we may not be successful in doing so.

Our efforts to commercialize our HTL^{tm} Technology may give rise to claims of infringement upon the patents or proprietary rights of others.

We own a license to use the HTL^{tm} Technology that we are seeking to commercialize but we may not become aware of claims of infringement upon the patents or rights of others in this technology until after we have made a substantial investment in the development and commercialization of projects utilizing it. Third parties may claim that the technology infringes upon past, present or future patented technologies. Legal actions could be brought against the licensor and us claiming damages and seeking an injunction that would prevent us from testing or commercializing the technology. If an infringement action were successful, in addition to potential liability for damages, we and our licensors could be required to obtain a claiming party s license in order to continue to test or commercialize the technology. Any required license might not be made available or, if available, might not be available on acceptable terms, and we could be prevented entirely from testing or commercializing the technology. We may have to expend substantial resources in litigation defending against the infringement claims of others. Many possible claimants, such as the major energy companies that have or may be developing proprietary heavy oil upgrading technologies competitive with our technology, may have significantly more resources to spend on litigation.

Technological advances could significantly decrease the cost of upgrading heavy oil and, if we are unable to adopt or incorporate technological advances into our operations, our HTLtm Technology could become uncompetitive or obsolete.

We expect that technological advances in the processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to occur. It is possible that those advances could make the processes and procedures, which are integral to the HTLtm Technology that we are seeking to commercialize, less efficient or cause the upgraded product being produced to be of a lesser quality. These advances could also allow competitors to produce upgraded products at a lower cost than that at which our HTLtm Technology is able to produce such products. If we are unable to adopt or incorporate technological advances, our production methods and processes could be less efficient than those of our competitors, which could cause our HTLtm Technology facilities to become uncompetitive.

The development of alternate sources of energy could lower the demand for our HTLtm Technology.

In addition, alternative sources of energy are continually under development. Alternative energy sources that can reduce reliance on oil and bitumen may be developed, which may decrease the demand for our HTLtm Technology upgraded product. It is also possible that technological advances in engine design and performance could reduce the use of oil and bitumen, which would lower the demand for such products.

The volatility of oil prices may affect our financial results.

Our revenues, operating results, profitability and future rate of growth are highly dependent on the price of, and demand for, oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Even relatively modest changes in oil prices may significantly change our 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.

The price of oil may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, 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, 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. Declines in oil prices would not only reduce our revenues, but could reduce the amount of oil we can economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations. In addition, a substantial long-term decline in oil prices would severely impact our ability to execute a heavy oil development program

Lower oil prices could negatively impact our ability to borrow.

The amount of borrowings available to us under our bank credit facilities are determined by reference to borrowing bases. The amounts of our borrowing bases are established by our lenders and are primarily functions of the quantity and value of our reserves. Our borrowing bases are re-determined at least twice a year to take into account changes in our reserve base and prevailing commodity prices. Commodity prices can affect both the value as well as the quantity of our reserves for borrowing base purposes as certain reserves may not be economic at lower price levels. Consequently, the amounts of borrowings available to us under our bank credit facilities could be adversely affected by extended periods of low commodity prices.

Our ability to sell assets and replace revenues generated from any sale of our existing properties depends upon market conditions and numerous uncertainties.

During 2006, we were involved in negotiations for a business combination transaction involving our China assets that, if completed, would have resulted in our China assets being owned and operated by a separate publicly traded company. Although the transaction was not completed, we continue to explore opportunities to generate capital for the ongoing development of our core HTL^{tm} business, which may involve the sale of some or all of our exploration, development and production assets in China and the U.S. There can be no assurance that we will sell any such assets nor that any such sale, if and when made, will generate sufficient capital for the ongoing development of our core HTL^{tm} business, which will require the acquisition of one or more properties hosting deposits of heavy oil. Our operating revenues and cash flows would likely decrease significantly following the sale of any material portion of our existing producing assets and would likely remain at lower levels until we were able to replace the lost production with production from new properties.

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 under generally accepted accounting principles in Canada and the U.S. 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 of Proved Oil and Gas Properties in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report.

Government regulations in foreign countries may limit our activities and harm our business operations.

We carry on business in China and we may, in the future, carry on business in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for the agreements through which we carry on business now or in the future, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation, which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

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

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment and the assumptions used regarding prices for oil and natural gas, production volumes, required levels of operating and capital expenditures, and quantities of recoverable oil reserves. Oil prices have fluctuated widely in recent years. Volatility is expected to continue and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil reserves will vary from those assumed in our estimates, and these variances may be significant. Also, we make certain assumptions regarding future oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates we report. In addition, actual results of drilling, testing and production and changes in natural gas and oil prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material.

Information in this document 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 availability and cost of capital; receipt of HTL^{tm} Technology process test results, additional seismic data or reprocessed existing data; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment, supplies and personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks and decisions of our joint working interest owners.

We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

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

Some of our properties are held under licenses and leases, working interests in licenses and leases or production sharing contracts. If we fail to meet the specific requirements of the instrument through which we hold our interest, it may terminate or expire. We cannot assure you that any or all of the obligations required to maintain our interest in each such license, lease or production sharing contract will be met. Some of our property 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 properties. The termination of our interests in these properties may harm our business.

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

There can be no assurance that the costs we incur on exploration or development will result in an economic return. We may misinterpret geologic or engineering data, which may result in significant losses on 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 costs of production or otherwise adversely affect our ability to realize an acceptable level of economic return on a particular project in a timely manner or at all.

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

There are hazards and risks inherent in drilling for, producing and transporting oil. These hazards and risks may result in loss of hydrocarbons, environmental pollution, personal injury claims, and other damage to our properties and third parties and include fires, natural disasters, adverse weather conditions, explosions, encountering formations with abnormal pressures, encountering unusual or unexpected geological formations, blowouts, cratering, unexpected operational events, equipment malfunctions, pipeline ruptures, spills, compliance with environmental and government regulations and title problems.

We are insured against some, but not all, of the hazards associated with our business, so we may sustain losses that could be substantial due to events that are not insured or are underinsured. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse impact on our financial condition and results of operations. We do not carry business interruption insurance and, therefore, the loss and delay of revenues resulting from curtailed production are not insured.

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

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. These laws and regulations govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues and 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 on 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 a contaminated site.

Under these 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 of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that 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.

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

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and, as a result, may enjoy a competitive advantage in accessing financial, technical and human resources. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

Our share ownership is highly concentrated and, as a result, our principal shareholder significantly influences our business.

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 20% 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. Given the technological nature 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. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

ITEM 1B. ***UNRESOLVED STAFF COMMENTS***

We have no unresolved staff comments from the SEC staff regarding our periodic or current reports filed under the Act.

ITEM 3. ***LEGAL PROCEEDINGS***

We are not currently a party to any material legal proceedings.

ITEM 4. ***SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS***

None.

PART II

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

Market Information

Our common shares trade on the NASDAQ Capital Market and the Toronto Stock Exchange. The high and low sale prices of our common shares as reported on the NASDAQ and Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ CAPITAL MARKET (IVAN)
(U.S.$)

	2007				2006			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	2.45	2.25	2.65	2.16	1.65	2.43	2.96	3.27
Low	1.43	1.77	1.67	1.19	1.18	1.40	2.26	1.25

TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2007				2006			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	2.33	2.36	2.99	2.53	1.89	2.72	3.31	3.75
Low	1.43	1.88	1.84	1.40	1.36	1.59	2.50	1.44

On December 31, 2007, the closing prices for our common shares were $1.56 on the NASDAQ Capital Market and Cdn.$1.55 on the Toronto Stock Exchange.

Exemptions from Certain NASDAQ Marketplace Rules

NASDAQ s Marketplace Rules permit foreign private issuers to follow home country practices in lieu of the requirements of certain Marketplace Rules, including the requirement that a majority of an issuer s board of directors be comprised of independent directors determined on the basis of prescribed independence criteria and the requirement that an issuer s independent directors have regularly scheduled meetings at which only independent directors are present.

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 a majority of our board of directors is comprised of independent directors, based on prescribed independence criteria, which differ slightly from the criteria prescribed in the NASDAQ Marketplace Rules and whether or not our independent directors hold regularly scheduled meetings at which only independent directors are present. Although applicable Canadian rules pertaining to corporate governance make reference, as part of a series of non-prescriptive corporate governance guidelines based on what are perceived to be best practices , to the desirability of:

a board comprised of a majority of independent directors, and

independent directors holding regularly scheduled meetings at which only independent directors are present,

there is no legal requirement in Canada that mandates a board comprised of a majority of independent directors or that independent directors hold regularly scheduled meetings at which only independent directors are present.

As of the date of this Annual Report on Form 10-K, our board of directors consists of 6 individuals who are independent and 6 individuals who are not independent, applying the criteria prescribed by applicable Canadian rules pertaining to corporate governance and the criteria prescribed by the NASDAQ Marketplace Rules. Our independent directors are A. Robert Abboud, Howard R. Balloch, J. Steven Rhodes, Robert A. Pirraglia, Brian Downey and Peter G. Meredith.

Effective as of the date of our next annual general meeting of shareholders (**AGM**) scheduled to be held on May 29, 2008, we plan to reduce the size of our board of directors from 12 directors to 7 directors by nominating only 7 individuals for election as directors at the AGM. See Item 10 Directors, Executive Officers and Corporate Governance . If all of the individuals we plan to nominate for election at the AGM are elected as directors, our board of directors will then consist of 5 individuals who are independent and 2 individuals who are not independent, applying the criteria prescribed by applicable Canadian rules pertaining to corporate governance and the criteria prescribed by the NASDAQ Marketplace Rules.

Our non-management directors hold regularly scheduled meetings at which only non-management directors are present but 3 of our non-management directors are not independent, applying the criteria prescribed by applicable Canadian rules pertaining to corporate governance and the criteria prescribed by the NASDAQ Marketplace Rules. If all of the individuals we plan to nominate for election at the AGM are elected as directors, one of our non-management directors will not be independent

Enforceability of Civil Liabilities

We are a company incorporated under the laws of the Yukon Territory of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling shareholders, officers and representatives of the experts named in this Annual Report on Form 10-K reside outside the U.S. and a substantial portion of their assets and our assets are located outside the U.S. As a result, it may be difficult for you to effect service of process within the U.S. upon the directors, controlling shareholders, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments obtained in the courts of the U.S. based upon the civil liability provisions of the federal securities laws or other laws of the U.S. 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 U.S., in original actions or in actions for enforcement of judgments of U.S. courts, of liabilities based solely upon civil liability provisions of the U.S. 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 on Form 10-K.

Holders of Common Shares

As at December 31, 2007, a total of 244,873,349 of our common shares were issued and outstanding and held by 227 holders of record with an estimated 36,130 additional shareholders whose shares were held for them in street name or nominee accounts.

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.

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* (Canada) (the **Investment Act**), which generally prohibits a reviewable investment by an entity 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. 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 2008 is Cdn.$295 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. 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.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are 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-U.S. 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 U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation, which 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 U.S. 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 on Form 10-K.

Performance Graph

See table under Executive Compensation set forth in Item 11 in this Annual Report on Form 10-K.

Sales of Unregistered Securities

During the year ended December 31, 2007, we issued securities, which were not registered under the Securities Act of 1933 (the **Act**), as follows:

in November 2007, we issued 2,000,000 common shares at a price of U.S.$2.00 to an institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act.

During the year ended December 31, 2006, we issued securities, which were not registered under the Act, as follows:

in February 2006, we issued 8,591,434 shares in exchange for an additional 40% working interest in the Dagang field to CITIC in a transaction exempt from registration under Rule 903 of the Act;

in March 2006, we issued 100 common shares at a price of U.S.$3.20 to an institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act;

in April 2006, we issued 11,400,000 special warrants at U.S.$2.23 per special warrant to institutional and individual investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercised to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in May 2006. Originally, one common share purchase warrant would entitle the holder to purchase one common share at a price of U.S.$2.63 exercisable until the fifth anniversary date of the special warrant date of issue. In September 2006 these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.

During the year ended December 31, 2005, we issued securities, which were not registered under the Act, as follows:

in February 2005, we issued a convertible promissory note in the principal amount of $6.0 million to an arm s length lender in a transaction exempt from registration under Rule 903 of the Act. The principal amount and all accrued and unpaid interest was convertible into common shares of the Company at a price of U.S.$2.25 per common share. The conversion rights were not exercised and expired in November 2005;

in April 2005, we issued 4,100,000 special warrants at a price of Cdn.$3.10 per special warrant to institutional and individual investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercised to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in July 2005. One common-share purchase warrant will entitle the holder to purchase one common share at a price of Cdn.$3.50 exercisable until the second anniversary date of the special warrant date of issue;

in April 2005, we issued 29,999,886 common shares in exchange for all of the issued and outstanding common shares of Ensyn in a transaction exempt from registration under Section 3(a)(10) of the Act;

in May 2005, we issued a convertible promissory note in the principal amount of $2.0 million to an arm s length lender in a transaction exempt from registration under Rule 903 of the Act. The principal amount and all accrued and unpaid interest was convertible into common shares of the Company at a price of U.S.$2.15 per common share. The conversion rights were not exercised and expired in November 2005;

in June 2005, we issued 1,500,000 common shares at a price of U.S.$1.10 to a Canadian institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act;

in July 2005, we issued 1,000,000 special warrants at a price of Cdn.$3.10 per special warrant to an institutional investor in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercised in November 2005 to acquire, for no additional consideration, one common share and one share purchase warrant. One common share purchase warrant will entitle the holder to purchase one common share at a price of Cdn.$3.50 exercisable until the second anniversary date of the special warrant date of issue;

in August 2005, we issued 1,500,000 common shares at a price of U.S.$1.10 to a Bahamian institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act;

in September 2005, we issued 1,514,706 common shares at a price of U.S.$1.87 to a Bahamian institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act;

in November 2005, we issued 2,000,000 common share purchase warrants to an arm s length lender in a transaction exempt from registration under Rule 903 of the Act. Each common share purchase warrant is exercisable to purchase one common share of the Company at a price of U.S.$2.00 per common share at any time until November 2007; and

in November 2005, we issued 11,196,330 special warrants at U.S.$1.63 per special warrant to four individual investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercised to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in December 2005. One common share purchase warrant will entitle the holder to purchase one common share at a price of U.S.$2.50 exercisable until the second anniversary date of the special warrant date of issue.

ITEM 6. ***SELECTED FINANCIAL DATA***

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report on Form 10-K. The financial statements have been prepared in accordance with generally accepted accounting principles (**GAAP**) applicable in Canada, which are not materially different from GAAP in the U.S. except as noted immediately below in Reconciliation to U.S. GAAP . See also Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 19 to our financial statements in this Annual Report on Form 10-K.

The following table shows selected financial information for the years indicated:

	December 31				
	2007	**2006**	**2005**	**2004**	**2003**
	(Stated in thousands of US dollars, except per share amounts)				
Results of Operations					
Revenues	33,517	48,100	29,939	17,997	9,659
Net loss	(39,207)(1)	(25,492)(1)	(13,512)(1)	(20,725)(1)	(30,179)(1)
Net loss per share basic and diluted	(0.16)	(0.11)	(0.07)	(0.12)	(0.20)
Financial Position					
Total assets	236,916	248,544	240,877	118,486	106,574
Long-term debt	9,812	4,237	4,972	2,639	833
Shareholders equity	197,287	228,386	204,767	103,586	100,537
Common shares outstanding (in thousands)	244,873	241,216	220,779	169,665	161,359
Cash Flow					
Cash provided (used) by operating activities	5,489	14,352	9,870	4,032	(1,522)
Capital investments	(31,638)	(17,842)	(43,282)	(46,454)	(15,391)

(1) Includes asset write-downs and provisions for impairment of \$6.1 million, \$5.4 million, \$5.6 million, \$16.6 million and \$23.3 million for 2007, 2006, 2005, 2004 and 2003, respectively. See Note 4 to our financial statements under Item 8 in this Annual Report on Form 10-K.

Reconciliation to U.S. GAAP

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the U.S. The material differences between Canadian and U.S. GAAP, which affect our financial statements, are described in detail in Note 19 to our financial statements in this Annual Report on Form 10-K.

Had we followed U.S. GAAP certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows:

	December 31				
	2007	**2006**	**2005**	**2004**	**2003**
	(Stated in thousands of US dollars, except per share amounts)				
Results of Operations					
Net loss	(27,392)	(42,422)	(12,106)	(19,696)	(27,086)
Net loss per share basic and diluted	(0.11)	(0.18)	(0.06)	(0.12)	(0.18)
Financial Position					
Total assets	216,655	216,365	224,935	105,791	94,024
Long-term debt	10,412	4,237	4,972	2,639	833
Shareholders equity	170,545	188,829	188,745	90,892	87,987
Cash Flow					
Cash provided (used) by operating activities	11,501	13,340	5,042	2,222	(4,051)
Capital investments	(31,371)	(16,830)	(38,454)	(44,644)	(12,862)

(1) Includes asset write-downs and provisions for impairment of $5.9 million, $23.5 million, $4.5 million, $15.0 million and $nil for 2007, 2006, 2005, 2004 and 2003, respectively. See Note 19 to our financial statements under Item 8 in this Annual Report on Form 10-K.

ITEM 7. ***MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

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THE FOLLOWING SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2007. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA (GAAP). THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 19 TO THE CONSOLIDATED FINANCIAL STATEMENTS.

OUR DISCUSSION AND ANALYSIS OF OUR OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON OUR WORKING INTEREST BASIS AFTER ROYALTIES. ALL TABULAR AMOUNTS ARE EXPRESSED IN THOUSANDS OF U.S. DOLLARS, EXCEPT PER SHARE AND PRODUCTION DATA INCLUDING REVENUES AND COSTS PER BOE.

Ivanhoe Energy s Business

Ivanhoe Energy is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserve base and production. Ivanhoe Energy plans to utilize technologically innovative methods designed to significantly improve recovery of heavy oil resources, including the application of the patented rapid thermal processing process (**RTP™ Process**) for heavy oil upgrading (**HTL™ Technology** or **HTL**^{tm}) and enhanced oil recovery (**EOR**) techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production (**E&P**) of oil and gas. Finally, the Company is exploring an opportunity to monetize stranded gas reserves through the application of the conversion of natural gas-to-liquids using a technology (**GTL Technology** or **GTL**) licensed from Syntroleum Corporation. Our core operations are in the United States and China, with business development opportunities worldwide.

Ivanhoe Energy s proprietary, patented heavy oil upgrading technology upgrades the quality of heavy oil and bitumen by producing lighter, more valuable crude oil, along with by-product energy which can be used to generate steam or electricity. The HTL^{tm} Technology has the potential to substantially improve the economics and transportation of heavy oil. There are significant quantities of heavy oil throughout the world that have not been developed, much of it stranded due to the lack of on-site energy, transportation issues, or poor heavy-light price differentials. In remote parts of the world, the considerable reduction in viscosity of the heavy oil through the HTL^{tm} process will allow the oil to be transported economically over long distances. In addition to a dramatic improvement in oil quality, an HTL^{tm} facility can yield large amounts of surplus energy for production of the steam and electricity used in heavy oil production. The thermal energy from the HTL^{tm} process would provide heavy oil producers with an alternative to increasingly volatile prices for natural gas that now is widely used to generate steam. Yields of the low-viscosity, upgraded product are greater than 85% by volume, and high conversion of the heavy residual fraction is achieved. In addition to the liquid upgraded oil product, a small amount of valuable by-product gas is produced, and usable excess heat is generated from the by-product coke.

HTL^{tm} can virtually eliminate cost exposure to natural gas and diluent, solve the transport challenge, and capture the majority of the heavy to light oil price differential for oil producers. HTL^{tm} accomplishes this at a much smaller scale and at lower per barrel capital costs compared with established competing technologies, using readily available plant and process components. As HTL^{tm} facilities are designed for installation near the wellhead, they eliminate the need for diluent and make large, dedicated upgrading facilities unnecessary.

Executive Overview of 2007 Results

During the year, the value attributed to our reserves of oil and gas based on a standardized measure of discounted future cash flows increased by 43% to $92.9 million of which $49.6 million is in China and $43.3 million in the U.S. Although these values increased principally as a result of significant year-over-year increases in oil prices, several other factors affected the Company s oil and gas activities for the year. Higher oil prices were offset by reduced production volumes, principally as a result of down-hole equipment issues in China and a lack of steaming equipment in the U.S. Both of these equipment issues have been resolved with a change in the supplier for certain equipment in China and the addition of a second steaming unit and the retrofit of an existing steaming unit in our California operation. In addition, total revenues decreased as a result of a $10.2 million increase in losses on derivative instruments that were required by the Company s bank loan agreements. General and administrative costs and business and technology expenses increased as the Company continued to invest significant resources in the development and commercial deployment of its patented HTL^{tm} heavy oil upgrading technology.

The following table sets forth certain selected consolidated data for the past three years:

	Year Ended December 31,		
	2007	**2006**	**2005**
Oil and gas revenue	$ 43,635	$ 47,748	$ 29,800
Net loss	$ (39,207)	$ (25,492)	$ (13,512)
Net loss per share	$ (0.16)	$ (0.11)	$ (0.07)

Average production (Boe/d)	1,870	2,178	1,738
Net operating revenue per Boe	$ 38.56	$ 39.77	$ 34.99
Cash flow from operating activities	$ 5,489	$ 14,352	$ 9,870
Capital investments	$ (31,638)	$ (17,842)	$ (43,282)

Financial Results   Year to Year Change in Net Loss

The following provides a summary analysis of our net loss for each of the three years ended December 31, 2007 and a summary of year-over-year variances for the year ended December 31, 2007 compared to 2006 and for the year ended December 31, 2006 compared to 2005:

	2007	Favorable (Unfavorable) Variances	2006	Favorable (Unfavorable) Variances	2005
Summary of Net Loss by Significant Components:					
Oil and Gas Revenues:	$ 43,635		$ 47,748		$ 29,800
Production volumes		*$ (6,732)*		*$ 8,888*	
Oil and gas prices		*2,619*		*9,060*	
Realized gain (loss) on derivative instruments	(1,647)	*(1,716)*	69	*69*	
Operating costs	(17,319)	*(1,186)*	(16,133)	*(8,530)*	(7,603)
General and administrative, less stock based compensation	(9,372)	*(1,724)*	(7,648)	*(60)*	(7,588)
Business and technology development, less stock based compensation	(8,600)	*(1,379)*	(7,221)	*(2,416)*	(4,805)
Acquisition costs		*736*	(736)	*(736)*	
Net interest	(312)	*(283)*	(29)	*982*	(1,011)
Unrealized loss on derivative instruments	(8,939)	*(8,446)*	(493)	*(493)*	
Depletion and depreciation	(26,524)	*6,026*	(32,550)	*(18,103)*	(14,447)
Stock based compensation	(3,729)	*(808)*	(2,921)	*(808)*	(2,113)
Write-downs of HTL^{tm} and GTL development costs				*636*	(636)
Impairment of oil and gas properties	(6,130)	*(710)*	(5,420)	*(420)*	(5,000)
Other	(270)	*(112)*	(158)	*(49)*	(109)
Net Loss	$ (39,207)	*$ (13,715)*	$ (25,492)	*$ (11,980)*	$ (13,512)

Our net loss for 2007 was $39.2 million ($0.16 per share) compared to our net loss in 2006 of $25.5 million ($0.11 per share). The increase in our net loss from 2006 to 2007 of $13.7 million was due to decrease of $5.8 million in combined oil and gas revenues and realized loss on derivative instruments, an increase in operating costs of $1.2 million, a $3.1 million increase in general and administrative and business and technology development expenses excluding stock based compensation and an $8.4 million increase in unrealized loss on derivative instruments. These increases were partially offset by a $6.0 million decrease for depletion and depreciation.

Our net loss for 2006 was $25.5 million ($0.11 per share) compared to our net loss in 2005 of $13.5 million ($0.07 per share). The increase in our net loss from 2005 to 2006 of $12.0 million was due mainly to an $18.1 million increase in depletion and depreciation offset by an increase of $17.9 million in oil and gas revenues offset by an $8.5 million increase in operating costs and a $2.5 million increase in general and administrative and business and technology development expenses excluding stock based compensation.

Significant variances in our net losses are explained in the sections that follow.

Revenues and Operating Costs

The following is a comparison of changes in production volumes for the year ended December 31, 2007 when compared to the same period in 2006 and for the year ended December 31, 2006 when compared to the same period for 2005:

	Years Ended December 31, Net Boe s		Percentage	Years Ended December 31, Net Boe s		Percentage
	2007	2006	Change	2006	2005	Change
China:						
Dagang	464,206	554,185	(16)%	554,185	282,582	96%
Daqing	19,379	20,946	(7)%	20,946	32,236	(35)%
	483,585	575,131	(16)%	575,131	314,818	83%
U.S.:						
South Midway	177,745	188,379	(6)%	188,379	196,428	(4)%
Spraberry	19,587	23,242	(16)%	23,242	27,940	(17)%
Others	1,513	8,309	(82)%	8,309	95,306	(91)%
	198,844	219,930	(10)%	219,930	319,674	(31)%
	682,429	795,061	(14)%	795,061	634,492	25%

Net production volumes in 2007 decreased 14% from 2006 due to a 16% decrease in production volumes in our China properties and a 10% decrease in our U.S. properties, resulting in decreased revenues of $6.7 million.

Net production volumes in 2006 increased 25% from 2005 due to an 83% increase in production volumes in our China properties offset by a 31% decrease in our U.S. properties, resulting in increased revenues of $8.9 million.

Oil and gas prices increased 6% per Boe in 2007 generating $2.6 million in additional revenue as compared to 2006. We realized an average of $64.86 per Boe from operations in China during 2007, which was an increase of $2.82 per Boe from 2006 prices and accounted for $1.3 million of our increase in revenues. From the U.S. operations, we realized an average of $61.71 per Boe during 2007, which was an increase of $6.85 per Boe and accounted for $1.3 million of our increased revenues. We expect crude oil prices and natural gas prices to remain volatile in 2008.

Oil and gas prices increased 28% per Boe in 2006 generating $9.1 million in additional revenue as compared to 2005. We realized an average of $62.04 per Boe from operations in China during 2006, which was an increase of $12.07 per Boe from 2005 prices and accounted for $7.1 million of our increase in revenues. From the U.S. operations, we realized an average of $54.86 per Boe during 2006, which was an increase of $10.85 per Boe and accounted for $2.0 million of our increased revenues.

The increased revenues from oil and gas price increases in 2007 were offset by settlements from our costless collar derivative instruments. As benchmark prices rise above the ceiling price established in the contract the Company is required to settle monthly (see further details on these contracts below under Unrealized Loss on Derivative Instruments). The Company realized a net loss on these settlements in 2007 of $1.6 million, $1.3 million of which was from the U.S. segment, the balance from the China segment. This compares to a net gain in 2006 of $0.1 million on U.S. contracts.

Operating costs, including production taxes and engineering and support costs, for 2007 increased $5.09, or 25%, per Boe, when compared to 2006. These costs increased $8.29, or 69%, per Boe, for 2006 when compared to 2005. Operating costs in absolute terms for 2007 increased $1.2 million when compared to 2006 and these costs increased $8.5 million in 2006 when compared to 2005.

China

Production Volumes 2007 vs. 2006

The December 31, 2007 exit production rate at Dagang was 1,900 Gross Bopd, compared to 1,877 Gross Bopd at the end of 2006. Normal field decline was offset by the production of 290 Gross Bopd from five new development wells completed and put on production in the second half of 2007. Overall, net production volumes decreased 16% at the Dagang field for 2007 as in addition to normal declines within the field, we incurred abnormal downtimes due to problems encountered with sub-surface equipment. We expect that these equipment issues have been resolved with a change in equipment suppliers. We expect that additional perforations, fracture stimulations and water flooding will help offset declines due to increasing water production in 2008. The expected production rates for 2008 will be similar to those averaged in 2007, but may be lower than the exit rate at December 31, 2007.

Production Volumes 2006 vs. 2005

Net production volumes increased 96% at the Dagang field for 2006. As a result of the 2005 development program, oil production volume increased by 22% or by 61.7 Mboe in 2006 when compared to 2005. During 2005 we placed 22 new wells on production and fracture stimulated 13 wells in the northern block of this project and in 2006 we completed one well, fracture stimulated 12 wells and re-completed 13 wells. Additionally, volumes at the Dagang field increased in 2006 when compared to 2005 by 74% or 209.9 Mboe due to the re-acquisition of Richfirst s 40% working interest in this project in February 2006. As at December 31, 2005, 39 wells were on production and producing 2,310 gross Bopd (1,080 net Bopd).

Our royalty percentage from the Daqing field was reduced from 4% to 2% in May 2005 when the operator of the properties reached payout of its investment. As a result, our share of production volumes decreased 35% for 2006 compared to the same period in 2005. In addition, production from the field is declining.

Operating Costs 2007 vs. 2006

Operating costs in China, including engineering and support costs and Windfall Levy, increased 31% or $6.30 per Boe for 2007 when compared to 2006. Field operating costs increased $4.01 per Boe. In addition to the excessive down hole maintenance problems mentioned above, which resulted in increased workover and maintenance costs, increased power costs, additional operator salaries and higher supervision charges in relation to reduced volumes contributed to the increase. As more fully described below, beginning March 26, 2006 the China oil operations became subject to the Windfall Levy. This resulted in a $1.94 per Boe increase for 2007 partially as a result of the 2007 being the first full year of the Levy and partially due to higher oil prices. Engineering and support costs for 2007 increased by $0.35 per Boe or 46% as we continue to reduce the number of capital projects. We expect costs in 2008 to remain consistent on a per barrel basis as compared to 2007. Decreases resulting from one-time maintenance projects in 2007 and the ability to charge CNPC for its share of operating costs, expected to be mid-way through 2008 once we reach commercial production , will be offset by an increase in office costs allocated to operations as we continue to reduce the number of capital projects.

Operating Costs 2006 vs. 2005

Operating costs in China, including engineering and support costs and Windfall Levy, increased 149% or $12.31 per Boe for 2006 when compared to 2005. Field operating costs increased due to high power costs, increased workover and maintenance costs, related supervision and increased treatment and processing fees attributable to higher water production rates. With the suspension of our drilling activity at our Dagang field in December 2005, a major portion of our Dagang field office costs, which were previously being capitalized, were expensed as part of our operating activities. Engineering and support costs increased due to a higher allocation of support to production as we reduced our capital activity in the Dagang field in 2006 when compared to 2005. The increase in production volume in 2006 due to the 2005 drilling program at the Dagang field, in relation to the level of support required to operate the field, results in the per Boe decrease for 2006 when compared to 2005.

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 crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. For financial statement presentation the Windfall Levy is included in operating costs. The Windfall Levy resulted in $5.74 per Boe of the overall increase in 2006 when compared to 2005.

U.S.

Production Volumes 2007 vs. 2006

As at December 31, 2007, we were producing 517 gross Boe/d (496 net Boe/d) at South Midway compared to 590 gross Boe/d (543 net Boe/d) as at December 31, 2006. U.S. production volumes decreased 10% in 2007 when compared to 2006 mainly due to a decline in production at South Midway resulting from steam generator downtime during the second and third quarters, along with certain wells taken offline to be soaked and steamed once that steaming operation came back on line. The purchase of a second steam generator and the retrofit of an existing generator should allow for a full steaming program for 2008. As well, we expect the current drilling program at South Midway to offset natural declines within this field and to provide additional future drilling locations. In addition to the natural declines in production within our Spraberry field in West Texas, production was also hampered by a key producer being down for repairs in the third quarter. We expect that production at our Spraberry field will continue its modest declines.

Production Volumes 2006 vs. 2005

U.S. production volumes decreased 31% in 2006 when compared to 2005 mainly as a result of the decline in production from the Knights Landing field which had been depleted to minimal levels at the end of 2005 and the sale of our Citrus property effective February 1, 2006.

In addition, our production at South Midway decreased 4% for 2006 primarily as a result of several wells in the southern expansion of South Midway being down while we made repairs to our steam facilities. Contributions from the two in-fill wells in the southern expansion and seven in-fill wells in the primary area of South Midway drilled and completed in the second half of 2006 were not a major impact until 2007. As at December 31, 2006, we were producing 590 gross Boe/d (543 net Boe/d) at South Midway compared to 536 gross Boe/d (499 net Boe/d) as at December 31, 2005.

Operating Costs 2007 vs. 2006

Operating costs in the U.S., including engineering and support costs and production taxes, increased 11% or $2.18 per Boe for 2007 when compared to 2006. Field operating costs increased $0.97 per Boe due to increases to maintenance costs and workovers at Spraberry and steaming projects in the diatomite formation at North Salt Creek. These increases were somewhat offset due to a reduction in our South Midway steaming operations as we were in the process of replacing a steam generator, including purchasing and subsequent retro fit, which was completed and put on line in the third quarter. We also had our other steam generator down for repairs during the second quarter. In addition to this overall increase, engineering and support costs for 2007 increased by $1.11 per Boe mainly due to a higher allocation of support to production as capital activity decreased. We anticipate operating expense to increase in 2008 mainly as a result of the steaming operations at South Midway operating at full capacity versus a reduced capacity in 2007 due to the reasons described above. We expect the 2008 operating costs at Spraberry to be consistent with 2007. We are uncertain about the expected operating expenses at North Salt Creek as we are currently evaluating recent steam stimulation tests.

Operating Costs 2006 vs. 2005

Operating costs in the U.S., including engineering and support costs and production taxes, in 2006 decreased $0.7 million in absolute terms from 2005. However, on a per Boe basis operating costs increased 25% or $3.90 per Boe in 2006 when compared to 2005. Field operating costs increased $3.00 per Boe for 2006 when compared to 2005, primarily resulting from increases in primary operating costs at South Midway due to several maintenance projects related to the processing facilities. Although costs in the South Midway steaming operations did not fluctuate significantly in absolute terms, they did make up a larger portion of the overall cost per Boe as production in other fields declined. Engineering support increased $0.58 per Boe for 2006, when compared to 2005 as the same level of support was required to operate the fields even though there was a decline in production. Production taxes were up $0.32 per Boe for 2006 when compared to 2005, largely as the result of an increase in ad valorem taxes at South Midway and our Spraberry field in West Texas.

* * *

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis, from 2005 to 2007 are detailed below:

	Year Ended December 31,								
	2007			2006			2005		
	China	U.S.	Total	China	U.S.	Total	China	U.S.	Total
Net Production:									
Boe	483,585	198,844	682,429	575,131	219,930	795,061	314,818	319,674	634,492
Boe/day for the year	1,325	545	1,870	1,576	603	2,178	863	876	1,738
	Per Boe			Per Boe			Per Boe		
Oil and gas revenue	$ 64.86	$ 61.71	$ 63.94	$ 62.04	$ 54.86	$ 60.06	$ 49.97	$ 44.01	$ 46.97
Field operating costs	18.08	15.41	17.30	14.07	14.44	14.17	7.49	11.44	9.48
Production tax (U.S.) and Windfall Levy (China)	7.68	1.25	5.81	5.74	1.15	4.47		0.83	0.42
Engineering and support costs	1.12	5.06	2.27	0.77	3.95	1.65	0.78	3.37	2.08
	26.88	21.72	25.38	20.58	19.54	20.29	8.27	15.64	12.00
Net operating revenue	37.98	39.99	38.56	41.46	35.32	39.77	41.70	28.37	34.99
Depletion	39.73	29.38	36.71	40.57	24.23	36.05	29.77	15.53	22.60
Net revenue (loss) from operations	$ (1.75)	$ 10.61	$ 1.85	$ 0.89	$ 11.09	$ 3.72	$ 11.93	$ 12.84	$ 12.39

General and Administrative

Our changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2007 when compared to the same period for 2006 and for the year ended December 31, 2006 when compared to the same period for 2005 were as follows:

	2007 vs 2006	2006 vs 2005
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ (705)	$ 739
U.S.	(342)	(498)
Corporate	(849)	(892)
	(1,896)	(651)
Less: stock based compensation	172	591
	$ (1,724)	$ (60)

General and Administrative 2007 vs. 2006

China

General and administrative expenses related to the China operations increased $0.7 million for 2007 mainly due to a decrease in allocations to capital investments as a result of fewer capital projects in 2007 when compared to 2006.

U.S.

General and administrative expenses related to U.S. operations increased $0.3 million in 2007. Allocations to capital investments and operations decreased $0.9 million as a result of less capital activity for 2007 when compared to 2006 and discretionary bonuses paid in 2007. This increase in expense was offset by a decrease of $0.5 million for salaries and benefits, which was a result of reallocation of resources to HTL^{tm} activities beginning in the second half of 2006 and continuing through all of 2007.

Corporate

General and administrative costs related to Corporate activities increased $0.8 million for 2007 when compared to 2006. The increase for 2007 was due to a $1.4 million increase in salaries and benefits partially resulting from discretionary bonuses paid in 2007, the addition of new executives mid way through 2006, and other key personnel added in 2007. This increase was offset by a decrease in outside legal costs of $0.2 million, a decrease in professional fees incurred to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (**SOX**) in the amount of $0.1 million and a $0.3 million decrease for a one time charge in 2006 for the write off of the deferred loan costs on the convertible loan that was paid by way of the issuance of common shares in the April 2006 private placement.

General and Administrative 2006 vs. 2005

China

General and administrative expenses related to the China operations decreased $0.7 million for 2006 due to a $1.1 million one time charge in 2005 for the write off of deferred costs incurred associated with financing discussions for our Dagang field development project. This decrease was primarily offset by an increase of $0.3 million in foreign currency losses.

U.S.

General and administrative expenses related to U.S. operations increased $0.5 million in 2006. Allocations to capital investments decreased $1.5 million as a result of less capital activity for 2006 when compared to 2005. This increase in expense was offset by a decrease of $0.7 million for bonuses accrued in 2005 compared to nil in 2006, a $0.2 million decrease in stock based compensation and a decrease of $0.2 million for a reduction in contract labor.

Corporate

General and administrative costs related to Corporate activities increased $0.9 million for 2006 when compared to 2005. The increase for 2006 was due to a $0.4 million increase in salaries and benefits (a $0.8 million increase in stock based compensation offset by a decrease of $0.3 million for bonuses accrued in 2005), a $0.2 million increase in outside legal costs, a $0.3 million increase in financial consulting, a $0.5 million increase in corporate governance costs and a $0.3 million increase for a one time charge in 2006 for the write off of the deferred loan costs on the convertible loan that was paid by way of the issuance of common shares in the April 2006 private placement. These increases were offset by a $0.7 million decrease in reduced professional fees incurred to comply with the provisions of Section 404 of SOX as a portion of the 2004 SOX review was performed in the first quarter of 2005. In addition, 2006 costs for SOX were lower as there were no start up costs that we experienced in 2005.

Business and Technology Development

Our changes in business and technology development, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2007 when compared to the same period for 2006 and for the year ended December 31, 2006 when compared to the same period for 2005 were as follows:

	2007 vs 2006	2006 vs 2005
Favorable (unfavorable) variances:		
HTLtm	$ (2,630)	$ (2,506)
GTL	615	(127)
	(2,015)	(2,633)
Less: stock based compensation	636	217
	$ (1,379)	$ (2,416)

Business and Technology Development 2007 vs. 2006

Business and technology development expenses increased $2.0 million in 2007 compared to 2006 as we continued to focus on business and technology development activities related to HTLtm opportunities. The overall increase in HTLtm related to salaries and benefits was $1.4 million. In addition to a reallocation of resources (see G&A explanations above) to HTLtm, and 2007 discretionary bonuses, key personnel were added to this segment throughout 2007 as the Company develops its commercialization program for its technology. This increase was partially offset by an increased $0.5 million allocation to capital investments. This segment also increased as a result of $0.3 million higher operating costs at the CDF. Operating expenses of the CDF to develop and identify improvements in the application of the HTLtm Technology are a part of our business and technology development activities. This increase was in part the result of several heavy oil upgrading runs in the first and second quarters of 2007, including a key Athabasca bitumen test run. The Company will use the information derived from the Athabasca bitumen test run for the design and development of full-scale commercial projects in Western Canada. In addition, the HTLtm segment increased $0.4 million as a result of higher outside engineering fees and legal fees related to patents and $0.6 million due to a shift in resources from GTL. The remainder of the increase is related to consulting fees and travel costs to develop opportunities for our HTLtm Technology. We expect a decrease in CDF operating expenses in 2008 when compared to 2007 as we have now fulfilled the primary technical objectives of the CDF.

Business and Technology Development 2006 vs. 2005

As in 2005 most of the focus of our business and technology development activities was on HTLtm opportunities. Operating expenses of the CDF to develop and identify improvements in the application of the HTLtm Technology are expensed as part of our business and technology development activities and contributed $1.1 million to the increase in business and technology development for HTLtm activities in 2006. Part of this increase was due to the CDF operating for a full year in 2006 versus a partial year in 2005. In addition contract services, including engineering work related to CDF processing runs and legal fees related to patents, increased $0.7 million in 2006. The remainder of the increase is related to consulting fees and travel costs to develop opportunities for our HTLtm Technology.

Write-off of Deferred Acquisition Costs

In February 2006, the Company signed a non-binding memorandum of understanding regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), a U.S. public corporation. In May 2006 the parties entered a definitive agreement for the transaction. CMA s bylaws stipulated that if the transaction was not completed by August 31, 2006 CMA would be required to dissolve and distribute its assets (substantially all of which was cash) to its shareholders. CMA requested, but was unable to obtain, an extension of this deadline from its shareholders. Since the transaction could not be completed by the August 31 deadline, the definitive agreement was terminated and the Company wrote off deferred acquisition costs previously capitalized in the amount of $0.7 million. There were no such costs in 2007 or 2005.

Net Interest

Net Interest 2007 vs. 2006

Interest expense was higher in 2007 when compared to 2006 partially due to an additional draw down on our U.S. loan and the funding of a new loan for China. These higher amounts were offset by a decrease related to the early pay off of the term note (see 2006 vs. 2005 analysis below). In addition, interest income decreased by $0.3 million as average cash balances were lower throughout 2007 when compared to 2006.

Net Interest 2006 vs. 2005

In 2005, we borrowed the full amount of a $6.0 million stand-by loan facility, which we arranged in 2004, and amended the loan agreement to provide the lender the right to convert unpaid principal and interest during the loan term to the Company s common shares. We finalized a second 8% convertible loan agreement with the same lender for $2.0 million. In the fourth quarter of 2005, these two convertible loans totaling $8.0 million were exchanged for a $4.0 million term note. This term note was paid off early in the second quarter of 2006. The reduction in interest and financing costs resulting from the reduction in these loans from year to year was $0.8 million. In addition, interest income increased by $0.6 million as average cash balances were significantly higher throughout 2006 when compared to 2005. These favorable increases were offset by a $0.4 million increase in interest and financing costs related to the note with CITIC. This note was part of the consideration for the re-acquisition of the 40% interest in the Dagang field.

Unrealized Loss on Derivative Instruments

As a result of a requirement of the Company s lenders, the Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 75% of the Company s estimated production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives have a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. Also as a result of a requirement of the Company s lenders, the Company entered into a costless collar derivative to minimize variability in its cash flow from the sale of approximately 50% of the Company s estimated production from its Dagang field in China over a three-year period starting September 2007. This derivative has a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using the WTI as the index traded on the NYMEX.

The Company is required to account for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value or a liability. These benchmark prices reached record highs in 2007. For the year ended December 31, 2007, the Company had $4.2 million unrealized losses in its U.S. segment and $4.6 million unrealized losses in its China segment on these derivative transactions. The $0.5 million unrealized loss for 2006 was related to the U.S. segment.

Depletion and Depreciation

The primary expense in this classification is depletion of the carrying values of our oil and gas properties in our U.S. and China cost centers over the life of their proved oil and gas reserves as determined by independent reserve evaluators. For more information on how we calculate depletion and determine our proved reserves see Critical Accounting Principles and Estimates Oil and Gas Reserves and Depletion in this Item 7.

Depletion and Depreciation 2007 vs. 2006

Depletion and depreciation decreased $6.0 million in 2007, partially due to reduced depletion of $3.6 million. The overall reduction in depletion was mainly the result of lower production rates which resulted in a decrease in depletion of $4.2 million for 2007. This decrease was somewhat offset by a higher depletion rate of $36.71 per Boe which resulted in additional depletion expense of $0.6 million. Reduced depreciation of the CDF as a result of a longer depreciation period also contributed to the overall decrease in depletion and depreciation in the amount of $2.4 million for 2007.

China

Decreases in production volumes in China resulted in a decrease in depletion expense of $3.7 million for 2007 when compared to 2006.

China s depletion rate decreased $0.86 per Boe to $39.73 for 2007 when compared to 2006, resulting in a $0.4 million decrease in depletion expense. The decrease in the rates from year to year was mainly due to a $5.4 million ceiling test write down in the fourth quarter of 2006. This decrease was somewhat offset by an increase to the depletable pool in the fourth quarter of 2007 for the impairment of the drilling costs associated with the second exploration well in the Zitong Block.

U.S.

The U.S. depletion rate for 2007 was $29.38 per Boe compared to $24.23 per Boe for 2006, an increase of $5.15 per Boe resulting in a $1.0 million increase in depletion expense. This increase was mainly due to the 2006 fourth quarter impairment of certain properties, including North Yowlumne, LAK Ranch and Catfish Creek, resulting in $4.8 million of those costs being included with our proved properties and therefore subject to depletion. In addition, the capital spending we incurred in 2007 was related to facilities, versus drilling, and therefore did not correspondingly increase our reserve base.

Additionally, decreases in production volumes in the U.S. accounted for $0.5 million of the decrease in depletion expense for 2007.

HTL^{tm}

Depreciation of the CDF is calculated using the straight-line method over its current useful life which is based on the existing term of the agreement with Aera Energy LLC to use their property to test the CDF. The end term of this agreement was extended in August 2006 from December 31, 2006 to December 31, 2008 and the useful life was extended to coincide with the new term of the agreement. In addition to the change in life, depreciation expense also decreased as a result of a reduction in the depreciable base during the second quarter of 2007 due to a portion of the payment from INPEX being applied against those costs.

Depletion and Depreciation 2006 vs. 2005

Depletion and depreciation increased $18.1 million in 2006, due to an increase in depletion rates of $13.45 per Boe resulting in additional depletion expense of $8.1 million for 2006. Additionally, higher production rates resulted in increase in depletion of $6.2 million for 2006. We began depreciating the CDF in 2006 which also contributed to the overall increase in depletion and depreciation in the amount of $3.8 million for 2006.

China

China s depletion rate for 2006 was $40.57 per Boe compared to $29.77 per Boe for 2005. The increase of $10.80 per Boe resulted in $6.2 million increase in depletion expense for 2006. This increase was due mainly to two factors:

We suspended new drilling activity in December 2005 at our Dagang field in order to assess production decline performances on recently drilled wells, as well as maximizing cash flow from these operations. As a result, we reduced our estimate of the overall development program and our independent engineering evaluators, GLJ Petroleum Consultants Ltd., revised downward their estimate of our proved reserves at December 31, 2005.

In the second quarter of 2005, we impaired the cost of our first Zitong block exploration well resulting in $12.5 million of those and other associated costs being included with our proved properties and therefore subject to depletion.

Additionally, increases in production volumes in China accounted for $7.8 million of the increase in depletion expense for 2006.

U.S.

The U.S. depletion rate for 2006 was $24.23 per Boe compared to $15.53 per Boe for 2005, an increase of $8.70 per Boe resulting in a $1.9 million increase in depletion expense. This increase was mainly due to the impairment of the remaining cost of our Northwest Lost Hills #1-22 exploration well as at December 31, 2005, resulting in $8.9 million of those costs being included with our proved properties and therefore subject to depletion commencing in the first quarter of 2006. In addition, the impairment of other properties in December 2006, including Yowlumne, LAK Ranch and Catfish Creek, resulted in $4.8 million of those costs being included with our proved properties and therefore subject to depletion commencing in the fourth quarter of 2006. Increases in revisions to reserve estimates at December 31, 2006, mainly at South Midway, slightly offset the additional costs being added to the pool. Production volume decreases in the U.S. resulted in a $1.6 million decrease in our depletion expense for 2006.

HTL^tm^

The CDF was in a commissioning phase as at December 31, 2005 and, as such, had not been depreciated as at December 31, 2005. The commissioning phase ended in January 2006 and the CDF was placed into service. In 2006 $3.8 million of depreciation was recorded for the CDF.

Write-Down of HTL^tm^ and GTL Development Costs

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Research and Development , for Canadian GAAP we capitalize technical and commercial feasibility costs incurred for HTL^tm^ or GTL projects, including studies for the marketability of the projects products, subsequent to executing an MOU. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in HTL^tm^ and GTL assets. For U.S. GAAP, all such costs are expensed as incurred.

In 2007 and 2006, we had no write downs for our HTL^tm^ and GTL projects. This compares to the write down of $0.3 million related to our GTL project in Bolivia and $0.3 million related to our MOU with Ecopetrol for a heavy crude project in Colombia in 2005.

Impairment of Oil and Gas Properties

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties , we evaluate each of our cost center s proved oil and gas properties for impairment on a quarterly basis. If as a result of this evaluation, a cost center s carrying value exceeds its expected future net cash flows from its proved and probable reserves then a provision for impairment must be recognized in the results of operations.

Impairment of Oil and Gas Properties 2007 vs. 2006

We impaired our China oil and gas properties by $6.1 million in 2007, compared to $5.4 million in 2006. The 2007 impairment was mainly the result of impairing our costs incurred in the Zitong block due to an unsuccessful second exploration well resulting in those costs of $17.6 million being included with the carrying value of proved properties for the ceiling test calculation.

Impairment of Oil and Gas Properties 2006 vs. 2005

We impaired our China oil and gas properties by $5.4 million in 2006, compared to $5.0 million in 2005. The 2006 impairment was mainly the result of increased operating costs of the Dagang field, including costs of the Windfall Levy established in March 2006.

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents decreased by $2.5 million for the year ended December 31, 2007 compared to an increase of $7.2 million for 2006 and a decrease of $2.6 million for 2005.

Operating Activities

Our operating activities provided $5.5 million in cash for the year ended December 31, 2007 compared to $14.4 million and $9.9 million for the same periods in 2006 and 2005. The decrease in cash from operating activities for the year ended December 31, 2007 was mainly due to a decrease in net production volumes of 14% offset by an increase in oil and gas prices of 6%, net of realized loss on derivative instruments associated with oil and gas operations. In addition, increases to operating costs, general and administrative and business and technology development expenses also reduced operating cash flows. The increases in cash from operating activities for the year ended December 31, 2006 was mainly due to an increase in net production volumes of 25% and an increase in oil and gas prices of 28%. The increase in net revenues for the year ended December 31, 2006 was partially offset by an increase of $2.5 million in general and administrative and business and technology development expenses, excluding stock based compensation for the year ended December 31, 2006 when compared to the same period in 2005.

Investing Activities

Our investing activities used $22.3 million in cash for the year ended December 31, 2007 compared to $25.6 million for the same period in 2006. For 2007 we increased our capital asset expenditures by $13.8 million mainly the result of increased exploration expenditures at our Zitong project of $9.1 million and increased development expenditures for new drilling at our Dagang project of $5.3 million. Capital spending related to HTL^{tm} increased by $2.7 million as expenditures for the FTF increased by $3.9 million but were offset by decreased expenditures of $1.2 million for the CDF. An offset to the increase in capital expenditures was the receipt of a payment of $9.0 million received from INPEX as payment for the Company s past costs related to its Iraq project and HTL^{tm} Technology development costs. This amount was offset by a decrease in cash inflows from asset sales of $1.0 million in the U.S. in 2007, compared to $6.0 million for the same period in 2006. In addition in 2006 we used $11.5 million more cash for investing activities related to changes in working capital items as we significantly reduced capital program accounts payable in our China operation.

Our investing activities used $25.6 million in cash for the year ended December 31, 2006 compared to $51.1 million used in investing activities for the same period in 2005. For 2006, we reduced our capital asset expenditures by $25.4 million principally as a result of reduced expenditures for new drilling at our Dagang project of $17.3 million, reduced exploration expenditures of $4.5 million at our Zitong project and reduced expenditures of $2.6 million on projects in Iraq. In 2006, we generated $6.0 million of cash from asset sales in the U.S. compared to nil for the year ended December 31, 2005. In addition, during 2005, we spent $18.6 million on the Ensyn merger, which was completed in April 2005, including $6.8 million on the acquisition of the remaining joint venture interest in the CDF, and we advanced $1.2 million under a consultancy agreement. These decreases in our investing activities for the year ended December 31, 2006 were partially offset by a $24.7 million increase in our non-cash working capital associated with our investing activities.

Financing Activities

Financing activities for the year ended December 31, 2007 consisted of three draws totaling $13.0 million ($12.4 million net of financing costs) on two separate loan facilities. This increase in borrowings was offset by scheduled debt payments of $2.5 million. In 2006 we repaid notes in the amount of $5.5 million prior to maturity, made scheduled repayments of long-term debt of $3.2 million offset by an initial draw on a bank loan facility of $1.5 million ($1.3 million net of financing costs). Financing activities in 2007 also consisted of $4.0 million received from the exercise of warrants compared to 2006 when there were no warrants exercised but there was a $25.3 million private placement of common shares.

Our financing activities provided $18.4 million in cash for year ended December 31, 2006 compared to $38.6 million of cash provided by financing activities for the year ended December 31, 2005. The $20.2 million decrease in cash from financing activities is mainly due to a $7.1 million decrease in cash from private placements and exercises of warrants and options in addition to a $13.7 million decrease in net debt financing.

In April 2006 the Company closed a private placement of 11.4 million special warrants at $2.23 per special warrant for a total of $25.4 million. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. All of the special warrants were subsequently exercised for common shares and common share purchase warrants. Each common share purchase warrant originally entitled the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing. In September 2007, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93. Of the proceeds, $4.0 million has been used to pay down long-term debt and the balance will be used to pursue opportunities for the commercial deployment of the Company s heavy oil upgrading technology, to advance its oil and gas operations and for general corporate purposes.

Outlook for 2008

Our 2007 capital program budget ranges from approximately $15 million to $20 million and will encompass both continuing development of our existing producing oil and gas properties to maximize near-term cash flow and to further the development and deployment of our proprietary HTL^{tm} oil upgrading technology. Management s plans include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to meet its capital investment and operating objectives. The Company intends to utilize revenue from existing operations to fund the continuing transition of the Company to a heavy oil exploration, production and upgrading company and non-heavy oil related investments in our portfolio will be leveraged or monetized to capture value and provide maximum return for the Company. No assurances can be given that we will be able to enter into one or more alternative business alliances with other parties or raise additional capital. If we are unable to enter into such business alliances or obtain adequate additional financing, we will be required to curtail our operations, which may include the sale of assets.

Contractual Obligations and Commitments

The table below summarizes and cross-references the contractual obligations and commitments that are reflected in our consolidated balance sheets and/or disclosed in the accompanying Notes:

	Payments Due by Year					
	Total	2008	2009	2010	2011	After 2011
	(Stated in thousands of U.S. dollars)					
Consolidated Balance Sheets:						
Long term debt current portion	$ 6,729	$ 6,729	$	$	$	$

Long term debt	9,812		412	9,400		
Asset retirement obligation	2,218		754			1,464
Long term obligation	1,900		1,900			
Other Commitments:						
Interest payable(1)	3,517	1,511	1,129	877		
Lease commitments	3,536	1,136	907	788	565	140
Zitong exploration commitment	22,500	4,500	9,000	9,000		
Total	$ 50,212	$ 13,876	$ 14,102	$ 20,065	$ 565	$ 1,604

(1) This is the estimated future interest payments on our long term debt using the rates of interest in effect as at December 31, 2007, including accretion of discount.

We have excluded our normal purchase arrangements as they are discretionary and/or being performed under contracts which are cancelable immediately or with a 30-day notification period.

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to U.S. GAAP except for those items disclosed in Note 19 to the Consolidated Financial Statements. For U.S. readers, we have detailed the differences and have also provided a reconciliation of the differences between Canadian and U.S. GAAP in Note 19 to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgments that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgments and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting We follow Accounting Guideline 16 Oil and Gas Accounting Full Cost (**AcG 16**) in accounting for our oil and gas properties. Under the full cost method of accounting, all exploration and development costs associated with lease and royalty interest acquisition, geological and geophysical activities, carrying charges for unproved properties, drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs directly related to capital projects and asset retirement costs are capitalized on a country-by-country cost center basis. As at December 31, 2007, the carrying values of our U.S. and China cost centers were $34.0 million and $62.8 million, respectively.

The other generally accepted method of accounting for costs incurred for oil and gas properties is the successful efforts method. Under this method, costs associated with land acquisition and geological and geophysical activities are expensed in the year incurred and the costs of drilling unsuccessful wells are expensed upon abandonment.

As a consequence of following the full cost method of accounting, we may be more exposed to potential impairments if the carrying value of a cost center s oil and gas properties exceeds its estimated future net cash flows than if we followed the successful efforts method of accounting. An impairment may occur if a cost center s recoverable reserve estimates decrease, oil and natural gas prices decline or capital, operating and income taxes increase to levels that would significantly affect its estimated future net cash flows. See Impairment of Proved Oil and Gas Properties below.

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 performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. Reserve numbers and values are only estimates and you should not assume that the present value of our future net cash flows from these estimates is the current market value of our estimated proved oil and gas reserves.

Reserve estimates are critical to many accounting estimates and financial decisions including:

- determining whether or not an exploratory well has found economically recoverable reserves. Such determinations involve the commitment of additional capital to develop the field based on current estimates of production forecasts, prices and other economic conditions.

calculating our unit-of-production depletion rates. Proved reserves are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. In 2007, oil and gas depletion of $25.1 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2007 would have changed by approximately $2.6 million assuming no other changes to our reserve profile. See Depletion below.

assessing our proved oil and gas properties for impairment on a quarterly basis. Estimated future net cash flows used to assess impairment of our oil and gas properties are determined using proved and probable reserves[1] See Impairment of Proved Oil and Gas Properties below.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the COGE Handbook modified to reflect SEC requirements.

Independent qualified reserves evaluators prepare reserve estimates for each property at least annually and issue a report thereon. The reserve estimates are reviewed by our engineers familiar with the property and by our operational management. Our CEO and CFO meet with our operational personnel to review the current reserve estimates and related disclosures and upon their review and approval present the independent qualified reserves evaluators reserve reports to our Board of Directors with a recommendation for approval. Our Board of Directors has approved the reserve estimates and related disclosures.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation, and may differ materially from estimated cash flows.

Depletion As indicated previously, our estimate of proved reserves are critical to calculating our unit-of-production depletion rates.

Another critical factor affecting our depletion rate is our determination that an impairment of unproved oil and gas properties has occurred. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. An unproved oil and gas property would likely be impaired if, for example, a dry hole has been drilled and there are no firm plans to continue drilling on the property. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches and there are no plans to drill on the property or to extend the term of the lease. We assess each of our unproved oil and gas properties for impairment on a quarterly basis. If we determine that an unproved oil and gas property has been totally or partially impaired we include all or a portion of the accumulated costs incurred for that unproved oil and gas property in the calculation of our unit-of production depletion rate. As at December 31, 2007, we had $4.4 million and $3.3 million of costs incurred on unproved oil and gas properties in the U.S. and China, respectively.

Our depletion rate is also affected by our estimates of future costs to develop the proved reserves. We estimate future development costs using quoted prices, historical costs and trends. It is difficult to predict prices for materials and services required to develop a field particularly over a period of years with rising oil and gas prices during which

[1] **Proved** oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic recoverability is supported by either actual production or a conclusive formation test. **Probable** reserves are those additional reserves that are less likely to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of estimated proved plus probable reserves.

there is generally increased competition for a limited number of suppliers. We update our estimates of future costs to develop our proved reserves on a quarterly basis.

Impairment of Proved Oil and Gas Properties We evaluate each of our cost centers proved oil and gas properties for impairment on a quarterly basis. The basis for calculating the amount of impairment is different for Canadian and U.S. GAAP purposes.

For Canadian GAAP, AcG 16 requires recognition and measurement processes to assess impairment of oil and gas properties (**ceiling test**). In the recognition of an impairment, the carrying value(1) of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate adjusted for political and economic risk on a country-by-country basis. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for $6.1 million, $5.4 million and $5.0 million in a ceiling test impairment for our China cost center for the years ended December 31, 2007, 2006 and 2005, respectively.

For U.S. GAAP, we follow the requirements of the SEC s Regulation S-X Article 4-10(c)4 for determining the limitation of capitalized costs. Accordingly, the carrying value[2] of a cost center s oil and gas properties cannot exceed the future net cash flows, discounted at 10%, of its proved reserves using period-end oil and gas prices and costs plus (i) the cost of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation less (iii) income tax effects related to differences between the book and tax basis of the properties. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for nil, $7.6 million and $2.8 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2007, 2006 and 2005, respectively, and $5.9 million, $15.9 million and $1.7 million for the years ended December 31, 2007, 2006 and 2005 for our China cost center.

Asset Retirement For Canadian GAAP, we follow Canadian Institute of Chartered Accountants (**CICA**) Section 3110, Asset Retirement Obligations which requires asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations. We measure the expected costs required to retire our producing U.S. oil and gas properties at a fair value, which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. We do not make such a provision for our oil and gas operations in China as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. Asset retirement costs are depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. The accretion of the liability for the asset retirement obligation is included with interest expense.

[2] For Canadian GAAP, the carrying value includes all capitalized costs for each cost center, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. This is essentially the same definition according to U.S. GAAP, under Regulation S-X, except that the carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

For U.S. GAAP, we follow SFAS No. 143, Accounting for Asset Retirement Obligations which conforms in all material respects with Canadian GAAP.

Research and Development We incur various expenses in the pursuit of HTLTM and GTL projects, including HTL™ Technology for heavy oil processing, throughout the world. For Canadian GAAP, such expenses incurred prior to signing an MOU, or similar agreements, are considered to be business and technology development expenses and are charged to the results of operations as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability of the projects products, we assess that the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in HTL™ or GTL assets. For the years ended December 31, 2007, 2006 and 2005, we wrote down nil, nil and $0.6 million, respectively, of capitalized negotiation and feasibility costs associated with our HTL™ and GTL projects which did not result in definitive agreements.

Additionally, we incur costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies we license or own. We follow CICA Section 3450 Research and Development Costs in accounting for the development costs of equipment and facilities acquired or constructed for such purposes. Development costs are capitalized and amortized over the expected economic life of the equipment or facilities commencing with the start up of commercial operations for which the equipment or facilities are intended. We review the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the investments in HTL™ and GTL assets.

Costs incurred in the operation of equipment and facilities used to develop or enhance HTL™ and GTL technologies prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred.

For U.S. GAAP, we follow SFAS No. 2, Research and Development . As with Canadian GAAP, costs of equipment or facilities that are acquired or constructed for research and development activities are capitalized as tangible assets and amortized over the expected economic life of the equipment or facilities commencing with the start up of commercial operations for which the equipment or facilities are intended. However, for U.S. GAAP such facilities must have alternative future uses to be capitalized. As with Canadian GAAP, expenses incurred in the operation of research and development equipment or facilities prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred. The major difference for U.S. GAAP purposes is that feasibility, marketing and related costs incurred prior to executing a definitive agreement are considered to be research and development costs and are expensed as incurred. For the years ended December 31, 2007, 2006 and 2005, we expensed $0.3 million, $1.0 million and $4.8 million, respectively, of feasibility, marketing and related costs incurred prior to executing definitive agreements.

Intangible Assets Our intangible assets consists of the underlying value of an exclusive, irrevocable license to deploy, worldwide, the RTP™ Process for petroleum applications (HTL™ Technology) as well as the exclusive right to deploy the RTP™ Process in all applications other than biomass and a master license from Syntroleum permitting us to use the Syntroleum Process in an unlimited number of projects around the world. For Canadian GAAP, we follow CICA Section 3062 Goodwill and Other Intangible Assets whereby intangible assets, acquired individually or with a group of other assets, are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their useful lives whereas intangible assets with indefinite useful lives are not amortized unless it is subsequently determined to have a finite useful life. Intangible assets are reviewed annually for impairment, or when events or changes in circumstances indicate that the carrying value of an intangible asset may not be recoverable. If the carrying value of an intangible asset exceeds its fair value or expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the carrying value of the intangible asset. The HTL^{tm} Technology and the Syntroleum GTL master license have finite lives, which correlate with the useful lives of the facilities we expect to develop that will use the technologies. The amount of the carrying value of the technologies we assign to each facility will be amortized to earnings on a basis related to the operations of the facility from the date on which the facility is placed into service. We evaluate the carrying values of the HTLTM Technology and the Syntroleum GTL master license annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of its fair market value.

For U.S. GAAP, we follow SFAS No. 142, Goodwill and Other Intangible Assets which conforms in all material respects with Canadian GAAP.

2007 Accounting Changes

On January 1, 2007 we adopted six new accounting standards that were issued by the Canadian Institute of Chartered Accountants (**CICA**): Handbook Section 1506 Accounting Changes (**S.1506**), Handbook Section 1530 Comprehensive Income (**S.1530**), Handbook Section 3251 Equity (**S.3251**), Handbook Section 3855 Financial Instruments Recognition and Measurement (**S.3855**), Handbook Section 3861 Financial Instruments Disclosure and Presentation (**S.3861**) and Handbook Section 3865 Hedges (**S.3865**). The Company has adopted the new standards o January 1, 2007 in accordance with the transitional provision in each respective section. Comparative figures have not been restated.

The objective of S.1506 is to prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. This Section is intended to enhance the relevance and reliability of an entity s financial statements and the comparability of those financial statements over time and with the financial statements of other entities. There was no material impact on adoption of this Section.

S.1530 introduces Comprehensive Income, which consists of Net Income and Other Comprehensive Income (OCI). OCI represents changes in Shareholder s Equity during a period arising from transactions and other events with non-owner sources. There was no material impact on adoption of this Section; there is no difference between the Net Loss presented in the accompanying statement of operations.

S.3251 establishes standards for the presentation of equity and changes in equity during a reporting period. There was no material impact on adoption of this Section.

S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under S.3861. It requires that financial assets and financial liabilities, including derivatives, be recognized on the balance sheet when the Company becomes a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value on initial recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held for trading, available for sale, held to maturity, loans and receivables, or other financial liabilities.

Financial assets

The Company s financial assets are comprised of cash and cash equivalents, accounts receivable, advances and other long-term assets. These financial assets are classified as loans and receivables or held for trading financial assets as appropriate. The classification of financial assets is determined at initial recognition. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price. Transaction costs for all financial assets are expensed as incurred.

Financial assets are classified as held for trading if they are acquired for sale in the short term. Cash and cash equivalents and derivatives in a positive fair value position are also classified as held for trading. Held for trading assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement. The estimated fair value of held for trading assets is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Loans and receivables are non-derivative financial assets with fixed or determinable payments. Accounts receivable, advances and certain other assets have been classified as loans and receivables. Such assets are carried at amortized cost, as the time value of money is not significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired.

The Company assesses at each balance sheet date whether a financial asset carried at cost is impaired. If there is objective evidence that an impairment loss exists, the amount of the loss is measured as the difference between the carrying amount of the asset and its fair value. The carrying amount of the asset is reduced with the amount of the loss recognized in earnings.

Financial liabilities

Financial liabilities are classified as held for trading financial liabilities or other financial liabilities as appropriate. Financial liabilities include accounts payable and accrued liabilities, derivative financial instruments, credit facilities and long term debt. The classification of financial liabilities is determined at initial recognition.

Held for trading financial liabilities represent financial contracts that were acquired for sale in the short term or derivatives that are in a negative fair market value position.

The estimated fair value of held for trading liabilities is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Other financial liabilities are non-derivative financial liabilities with fixed or determinable payments.

Short term other financial liabilities are carried at cost as the time value of money is not significant. Accounts payable and accrued liabilities, notes payable and credit facilities have been classified as short term other financial liabilities. Gains and losses are recognized in income when the short term other financial liability is derecognized or impaired. Transaction costs for short term other financial liabilities are expensed as incurred.

Long term other financial liabilities are measured at amortized cost. Long-term debt has been classified as long term other financial liabilities. Transaction costs for long term other financial liabilities are deducted from the related liability and accounted for using the effective interest rate method.

Derivative Financial Instruments

The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows. The Company currently uses costless collar derivative instruments to manage this exposure.

Derivative financial instruments are classified as held for trading and recorded on the consolidated balance sheet at fair value, either as an asset or as a liability under other current financial assets or other current financial liabilities, respectively. Changes in the fair value of these financial instruments, or unrealized gains and losses, are recognized in the statement of operations as revenues in the period in which they occur.

Gains and losses related to the settlement of derivative contracts, or realized gains and losses, are recognized as revenues in the statement of operations.

Contracts to buy or sell non-financial items that are not in accordance with the Company s expected purchase, sale or usage requirements are accounted for as derivative financial instruments.

There was no material impact on adoption of Section 3855.

S.3861 establishes standards for presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed about them. The presentation aspect of this standard deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. The disclosure aspect of this standard deals with information about factors that affect the amount, timing and certainty of an entity s future cash flows relating to financial instruments. This Section also deals with disclosure of information about the nature and extent of an entity s use of financial instruments, the business purposes they serve, the risks associated with them and management s policies for controlling those risks. There was no material impact on adoption of this Section.

S. 3865 specifies the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of foreign currency exposure of net investment in self-sustaining foreign operations. The Company has not elected to designate any financial derivatives as accounting hedges at this time.

For U.S. GAAP, we follow SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (**SFAS 133**) which conforms in all material respects with Canadian GAAP with respect to the treatment of costless collars.

Impact of New and Pending Canadian GAAP Accounting Standards

In February 2008, the Canadian Institute of Chartered Accountants (CICA) issued Section 3064, Goodwill and Intangible assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Company is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements.

In December 2006, the CICA approved Handbook Section 1535 Capital Disclosures (**S.1535**), Handbook Section 3862 Financial Instruments Disclosures (**S.3862**), and Handbook Section 3863 Financial Instruments Presentation (**S.3863**). S.1535 establishes standards for disclosing information about an entity s capital and how it is managed. The objective of S.3862 is to require entities to provide disclosures in their financial statements that enable users to evaluate both the significance of financial instruments for the entity s financial position and performance; and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. The purpose of S.3863 is to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. These Sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007 and the latter two will replace S.3861. Management will adopt these new disclosure requirements in the first quarter of 2008.

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada s Accounting Standards Board (AcSB) ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The AcSB has developed and published a detailed implementation plan, with a changeover date for fiscal years beginning on or after January 1, 2011. This convergence initiative is in its early stages as of the date of these annual financial statements. Management has commenced a program of analyzing the Company s historical financial information in order to assess the impact of the convergence on its financial statements.

Impact of New and Pending U.S. GAAP Accounting Standards

In December 2007, the Financial Accounting Standards Board (**FASB**) issued Statement of Financial Accounting Standards No. 141 (revised 2007), Business Combinations (**SFAS No. 141(R)**) and Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements (**SFAS No. 160**). Effective for fiscal years beginning after December 15, 2008, the standards will improve, simplify, and converge internationally the accounting for business combinations and the reporting of noncontrolling interests in consolidated financial statements. SFAS 141(R) requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 160 requires all entities to report noncontrolling (minority) interests in subsidiaries in the same way as equity in the consolidated financial statements. Management is currently evaluating the impact of the adoption of these new standards on its financial statements.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (including an amendment of FASB Statement No. 115) (**SFAS No. 159**). The statement would create a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. This Statement is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Management has concluded that the requirements of this recent statement will not have a material impact on its financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (**SFAS No. 157**). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement does not require any new fair value measurements; however, for some entities the application of this statement will change current practice. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, although early adoption is permitted. Management has concluded that the requirements of this recent statement will not have a material impact on its financial statements.

Off Balance Sheet Arrangements

At December 31, 2007 and 2006, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Related Party Transactions

The Company has entered into agreements with a number of entities, which are related through common directors or shareholders, to provide administrative or technical personnel, office space or facilities. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $3.3 million, $3.0 million and $3.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. As at December 31, 2007 and 2006, amounts included in accounts payable under these arrangements were $0.2 million and $0.3 million, respectively.

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 natural gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure than we do. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets than we can 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 more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for producing oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to 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 conventional oil and gas and HTL^{tm} operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. We believe that our operations comply in all material respects with applicable environmental laws.

In the U.S., environmental laws and regulations, implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

China continues to develop and implement more stringent national environmental protection regulations and standards for different industries. Projects are currently monitored by provincial and local governments based on the approved standards specified in the environmental impact statement prepared for individual projects.

Environmental Provisions

As at December 31, 2007, a $1.5 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S. and $0.7 million for the removal of the CDF and restoration of the Aera site occupied by the CDF. The future cost of these obligations is estimated at $3.9 million and $0.7 million for the U.S. wells and CDF, respectively. We do not make such a provision for our oil and gas operations in China, as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. During 2007, our provision for future site restoration and plugging and abandonment of U.S. wells stayed constant and we increased our provision for the CDF by $0.2 million.

Government Regulations

Our business is subject to certain U.S. and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years both in the U.S. and China, 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.

ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We are exposed to normal market risks inherent in the oil and gas business, including equity market risk, commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

NON-TRADING

Equity Market Risks

We currently have limited production in the U.S. and China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities. Based on our current plans, we estimate that we will need approximately $15.0 to $20.0 million to fund our capital investment programs for 2008.

We can give no assurance that we will be successful in obtaining financing as and when needed. Factors beyond our control may make it difficult or impossible for us to obtain financing on favorable terms or at all. Failure to obtain any required financing on a timely basis may cause us to postpone our development plans, forfeit rights in some or all of our projects or reduce or terminate some or all of our operations.

Commodity Price Risk

Commodity price risk related to crude oil prices is one of our most significant market risk exposures. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices, North American supply and demand and local market conditions. Based on the Company s 2008 estimated worldwide crude oil production levels, a $1.00/Bbl change in the price of oil, would increase or decrease net income and cash from operations for 2008 by $0.3 million. Based on the Company s 2008 estimated natural gas production levels and consumption levels in its oil operations, a $0.50/Mcf increase in the price of natural gas would decrease our net income and cash from operations for 2008 by $0.1 million and a $0.50/Mcf decrease in the price would have the opposite effect on our net income and cash from operations.

We periodically engage in the use of derivatives to minimize variability in our cash flow from operations and currently have costless collar contracts put in place as part of our bank loan facilities. The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 75% of the Company s