IVANHOE ENERGY INC
Form 10-K
March 15, 2006

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, 2005

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	**98-0372413**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
654-999 Canada Place Vancouver, British Columbia, Canada	**V6C3E1**
(Address of principal executive offices)	(Zip Code)

(604) 688-8323

(Registrant s telephone number, including area code)

No Changes

(Former name, former address and former fiscal year, if changed since last report)

None

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. Yes o No þ

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. Yes o No þ

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.

Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

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

As of June 30, 2005, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $471,351,580 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 February 28, 2006
Common Shares, no par value	229,430,769 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:

	2005	**2004**	**2003**	**2002**	**2001**
Closing	$0.86	$0.83	$0.77	$0.63	$0.63
Low	$0.79	$0.72	$0.63	$0.62	$0.62
High	$0.87	$0.85	$0.77	$0.66	$0.67
Average Noon	$0.83	$0.77	$0.71	$0.63	$0.65

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 28, 2006 was $ 0.88 ($1.00 = Cdn.$1.14).

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; future benefits to be derived from the acquisition of Ensyn Group, Inc. (**Ensyn**); uncertainties regarding the potential success of our oil and gas exploration and development properties in the U.S. and China; uncertainties regarding the potential success of heavy-to light oil upgrading and gas-to-liquids technologies; 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 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 t similar terminology. 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 Securities and Exchange Commission s website at http://www.sec.gov/.

ITEMS 1 AND 2 BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an independent international energy company engaged in the exploration for and production of oil and gas, enhanced oil recovery and natural gas projects and the application of heavy oil upgrading using a proprietary rapid thermal processing technology (**RTP^{TM} Technology**) and the conversion of natural gas-to-liquids (**GTL**) using a licensed technology. Our core operations are in the United States and China, but we have business and product development opportunities worldwide.

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

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.

HISTORICAL OVERVIEW

We were incorporated pursuant to the laws of the Yukon, 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.

Since 1996 we have pursued a business plan of evaluating and exploiting potentially attractive opportunities to acquire, develop and explore for oil and gas, principally in California, China and in the late 1990 s, in Russia. Our business activities in Russia concluded in 2000.

In 2000, we acquired a master license from Syntroleum Corporation (**Syntroleum**) to use its proprietary GTL technology to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products.

On April 15, 2005, we acquired all the issued and outstanding common shares of Ensyn whereby we acquired an exclusive, irrevocable license to Ensyn s RTP^{TM} Technology for use in the upgrading of heavy oil to produce lighter, more valuable crude oil at lower costs and in smaller size facilities than required by conventional technologies.

CORPORATE STRATEGY

Our objective is to create shareholder value by finding and developing oil and gas reserves principally through the application of our RTP^{TM} Technology for upgrading heavy oil, and as well, through the monetization of stranded gas reserves through the application of the GTL technology licensed from Syntroleum and through conventional exploration and production (**E&P**) of oil and gas, primarily in the U.S. and China.

The most significant element of our strategy was put in place with the acquisition of Ensyn in the second quarter of 2005 (**Merger**). We intend to apply Ensyn s leading-edge RTP^{TM} Technology as a critical, value added tool in the development of reserves and production and to establish partnerships with owners of heavy oil reserves where we will build, own and operate commercial heavy-to-light facilities. The use of the RTP^{TM} Technology will allow us to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude oil at lower costs and in smaller size facilities than required by conventional technologies. Our heavy oil upgrading technology has four key competitive advantages:

- It is field-located and effective at a relatively small minimum scale of 10,000 to 15,000 barrels per day;

- The value of the upgraded liquid product means the producer is able to capture the majority of the price differential between heavy and light crude oil;

- The upgraded product is easily transported by pipeline without the need for light blend oils; and

The process generates significant on-site excess energy, replacing natural gas for production of steam and/or power used in heavy oil recovery.

The RTP™ Technology adds significant incremental value, flexibility and risk avoidance to heavy oil producers in areas with existing infrastructure and alternative development options, such as Western Canada, and is also a unique option for the development of stranded heavy oil or tar sands deposits that cannot be produced due to lack of on-site energy or transportation challenges. We believe that these innovative characteristics of this heavy-to-light oil process will provide us with an opportunity to significantly increase our base of oil reserves worldwide through joint venture and production sharing arrangements. We consider the acquisition of Ensyn a major advance in the implementation of our corporate strategy because it will offer significant potential for broadening our access to project opportunities that might not otherwise be available to us.

Another key part of our strategy is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world s crude oil becomes more sour and heavy. We believe that Syntroleum s proprietary GTL technology holds significant potential for the economic production of synthetic fuels from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies, we believe that the Syntroleum technology offers several key advantages. We believe the Syntroleum plant is safer to operate because, unlike competing technologies, the conversion process utilizes compressed air rather than pure oxygen and that plant construction is less expensive.

Our third objective is to focus on exploiting our existing mineral interest holdings, particularly in California s San Joaquin Basin and at the Dagang oil field and the Zitong gas projects in China. Our plan is to identify new opportunities where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our heavy oil and GTL opportunities.

HEAVY OIL PROCESSING TECHNOLOGY

RTP ™ License

With the Merger with Ensyn, we acquired an exclusive, irrevocable license to deploy, worldwide, the RTP™ Technology for petroleum applications as well as the exclusive right to deploy RTP™ Technology in all applications other than biomass. We believe that the value of owning an exclusive, irrevocable right to the technology can be maximized by using it to create opportunities to acquire interests, and actively participate, in heavy oil development projects by building and owning the projects rather than licensing the technology to third parties.

RTP™ Process

Heavy oil deposits throughout the world, including bitumen, represent a potentially massive resource, holding quantities of heavy oil more than double the existing global reserves of light or conventional oil. Heavy oil extraction and transportation presents a number of technological challenges and typically requires extensive and cost-intensive infrastructure. Higher viscosity makes the transportation of heavy oil through conventional pipelines difficult or impossible unless it is first blended with lighter, lower viscosity oil or expensive diluents. As a result, less than 1% of the world s heavy oil deposits are currently under active development. We believe that we have a unique opportunity to accumulate reserves by acquiring interests in stranded heavy oil deposits that would otherwise be uneconomic to develop through conventional means and developing them on an incremental, cost-efficient basis using RTP Technology.

The RTP™ Technology upgrades the quality of heavy oil by producing lighter, more valuable crude oil. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and potentially reduces transportation costs to marketing points. The RTP™ Technology uses readily available plant and process components. We believe that the RTP Technology will offer a number of potential cost saving and revenue-enhancement benefits. The reduction or elimination of the need for an external energy source, usually natural gas, for steam production used in the heavy oil recovery process, often a substantial added cost to conventional producers, could significantly reduce the operating cost of extracting the heavy oil. The RTP Technology upgraded oil is likely to command a higher market price, reducing what would otherwise be a significant price differential between heavy and light oil. The price paid to producers for heavy oil is lower than the price paid for light oil as the heavy oil requires additional refining. Unlike conventional heavy oil extraction facilities, which usually must be constructed on a large scale in order to be economical and therefore require a significant up-front capital investment, we expect to be able to deploy the RTP Technology on a relatively small scale and independent of refineries, which should allow us to develop smaller heavy oil fields that would otherwise be uneconomic to exploit using conventional technologies. The scalability of RTP Technology-equipped facilities offers the potential to incrementally develop heavy oil deposits financed by cash flow. Given their limited infrastructure requirements, RTP Technology-equipped facilities can be located in relatively remote areas where constructing conventional facilities would not be feasible.

RTP™ Project Plans and Opportunities

Aera Energy LLC Agreement

In August 2004, Ivanhoe Energy HTL Inc. (**IE HTL**) (formerly Ensyn Group, Inc.) and Aera Energy LLC (**Aera**) signed an agreement that set out the financial and operational parameters for a commercial heavy oil project using the RTP Technology in Aera s California heavy oil fields. We are continuing to negotiate for a definitive agreement to build an RTP Plant that would yield upgraded, heavy oil and excess thermal energy. The excess thermal energy from this RTP Plant would provide Aera an alternative to volatile natural gas prices and thereby lower Aera s operating expense associated with steam generation, the most significant component of their operating expense. The RTP Plant, if completed, would be owned and operated by IE HTL. Additional RTP Plants, with a combined heavy oil throughput of up to 45,000 barrels per day, may be installed on Aera s properties if the performance of the initial RTP Plant meets expectations. Aera is one of California s leading oil producers.

RTP™ Commercial Demonstration Facility

In 2004, an RTP™ Commercial Demonstration Facility (**RTP™ CDF**) was constructed by an Ensyn joint venture on Aera s property in the Belridge Field for the purpose of demonstrating the RTP™ Technology on a commercial scale. In March 2005, initial performance testing of the RTP™ CDF was completed successfully and the results of the test were verified by the independent consulting firms Muse, Stancil & Co. and Purvin & Gertz Inc. The RTP™ CDF demonstrated an overall processing capacity of approximately 1,000 barrels-per-day of raw, heavy oil and a hot section capacity of 300 barrels-per-day. We have successfully completed an extended program of technical and operational enhancements to the RTP™ CDF at a cost of $0.6 million, which culminated in a successful extended run in January 2006 that achieved a number of important performance goals. We are now building on these positive test results by expanding our testing of crude oil from potential resource partners with an initial focus on heavy crude oil from California and Western Canada, including bitumen from Canada s Athabasca tar sands region. The RTP™ CDF runs to date have successfully demonstrated a number of commercial configurations and processing alternatives, including both high yield (once through) and high quality (recycle) modes of operation. A number of process enhancements have been validated during the RTP™ CDF test program, including gas sulphur capture, heavy metals capture and crude acidity reduction.

RTP™ Plant Design Package

In the second quarter of 2005, we completed a preliminary design package for a cost of $1.2 million prepared by Colt Engineering Corporation for a 15,000 barrels-per-day feed of raw, heavy oil (5,000 barrels per day hot-section) commercial RTP facility (**RTP™ Plant**). The design package included various studies and costing estimates for both high yield and high quality schemes that would be designed to produce maximum steam or electrical generation for each configuration at varying levels of heavy oil input into the plant. The location that was part of the design basis is Aera s Belridge oil field using the heavy oil produced there as feedstock. This heavy oil is moderately heavy at 13° API and is similar to many target heavy oil resources found worldwide, including Canada s heavy oil from the Cold Lake and Peace River areas of Alberta. The various plant configurations were evaluated as well as the capital estimates that are being used in our economic models.

ConocoPhillips Canada Resources Corp. Agreement

Under a pre-existing agreement between IE HTL and ConocoPhillips Canada Resources Corp. (**ConocoPhillips Canada**), certain non-exclusive rights to use the RTP Technology for petroleum applications in Canada were granted. ConocoPhillips Canada has the right, through August 2010, to place orders for RTP Plants with input capacity of up to 250,000 barrels-per-day. Should ConocoPhillips Canada install RTP Plants, IE HTL is entitled to receive royalties per barrel after the first 50,000 barrels-per day of feedstock input capacity. In addition to these rights, ConocoPhillips Canada has the right to test Athabasca bitumen in the RTP™ CDF, for a fee. Plans are currently underway by ConocoPhillips Canada to transport a quantity of bitumen to the RTP™ CDF site for an extended test run, in a variety of test configurations. A test program has been agreed to with ConocoPhillips Canada and when completed, would represent a significant advancement in our targeted test program with resource owners, particularly those in the vast Athabasca tar sands region in Alberta.

GAS-TO-LIQUIDS TECHNOLOGY

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum s proprietary GTL process in an unlimited number of projects with no limit on production volume. In June 2003, we gave up our rights for license fee credits for the $10.0 million we paid for the master license and $2.0 million of other credits. In consideration, Syntroleum removed certain territorial restrictions to our master license, which will enable us to pursue GTL project opportunities worldwide. Syntroleum has also agreed that, in respect of GTL projects in which both companies participate, no additional license fees or royalties will be payable. Both companies have the right to pursue GTL projects independently, but we would be required to pay Syntroleum the normal license fees and royalties in such projects.

Syntroleum Process

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**) 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.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process uses air when converting natural gas into synthetic hydrocarbons (i.e. diesel, naphtha and LPG). 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.

From our perspective, the attraction of the Syntroleum Process lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but requires innovative gas processing to produce products that can be marketed on an economic basis. Operators consider natural gas to be stranded based on the relative size of the fields and their remoteness from comparable sized markets.

GTL Projects

We have performed detailed project feasibility studies for the construction, operation and cost of plants from 45,000 to 90,000 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. Our capital investment in GTL activities increased to $1.1 million for 2005 compared to $0.1 million in 2004.

In 2004, we initiated a feasibility study to convert coal to synthesis gas (**CTL**) as a feedstock for the Syntroleum Fischer-Tropsch process. The objective of the study is to explore opportunities for converting coal into clean burning CTL fuels in parts of the world where there is a relatively cheap supply of sizeable coal deposits. China and Mongolia both have large coal deposits and China in particular has a rapidly growing need for clean energy.

Egypt

In 2005, we signed a memorandum of understanding (**MOU**) with Egyptian Natural Gas Holding Company (**EGAS**), the state organization charged with the management of 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. EGAS has agreed to commit up to 4.2 trillion cubic feet of natural gas, or approximately 600 MMcf/d for the anticipated 20-year operating life of the proposed project, if the study indicates that a GTL project is economically feasible. We completed an engineering design of a GTL plant to incorporate the latest advances in the GTL technology and are also in the process of obtaining an updated market analysis for GTL products to reflect changes since the original evaluation was completed several years ago. Plant capacity options of 45,000 and 90,000 Bbls/d will be evaluated. If the feasibility study indicates that a GTL plant is economically viable the parties will enter into negotiations for a definitive agreement for the development of a project. For 2005, we incurred costs for engineering, design and market studies totaling $1.1 million.

Bolivia

In July 2003, we signed a participation agreement with Repsol-YPF Bolivia S.A. (**Repsol**) and Syntroleum for a commercialization study to build a 90,000Bbls/d GTL plant in southern Bolivia. The commercialization study included an analysis of alternative plant sites, transportation logistics and screening economics conducted by representatives from Ivanhoe, Repsol and Syntroleum. The initial phase of the commercialization study was completed in 2004 and we determined that under Bolivia s current hydrocarbon tax regulations a 90,000 Bbls/d GTL plant could be commercially viable. However, due to the passing of a referendum to overhaul Bolivia s tax regulations in the third quarter of 2004 we elected to postpone any further work on the commercialization study. The participation agreement with Repsol and Syntroleum expired at the end of 2004 and we elected not to renew the participation agreement. Due to the uncertainty in Bolivia and as a result of our on-going evaluation of our GTL projects, we wrote down our $0.3 million investment in 2005.

OIL AND GAS PROPERTIES

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

California

Over the past seven years, we acquired interests in a number of properties in and around the San Joaquin Basin. In 2004, we acquired properties in the Knights Landing field in the Sacramento Gas Basin and established production in the Citrus field in the San Joaquin Basin. To date, our South Midway, Citrus, Knights Landing and North Salt Creek properties contain proved reserves and have wells on production. We cannot assure you that any of our other prospects in California will result in the development of commercially viable production.

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.

South Midway

We currently have 57 producing wells in South Midway and are the operator, with a working interest of 100% and a 93% net revenue interest. In 2005, we drilled four new wells on the South Midway properties, consisting of one step-out well, one exploratory well and two temperature observation wells. The exploratory well was successful and plans are underway for a cycle of steam in early 2006 to realize the well s maximum production. Our capital investment in South Midway of $1.1 million for 2005 was equal to our investment level in 2004 when we drilled six development wells and one exploratory well. Four of the six development wells were completed as producers.

In the southern expansion area of South Midway, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into four wells. The project began in October 2005 and by year-end 2005 the production performance was showing good response to the continuous injection. If successful, continuous steam injection could increase recovery of the oil in place by an estimated 50-70%, similar to recovery in other fields in the area, and add additional probable reserves to our proved undeveloped reserves. Current production from the southern expansion area is approximately 160 gross Bopd and total South Midway production is approximately 530 gross Bopd.

Citrus

In October 2005, we farmed out our working interest for a carried interest in one exploration well in 640 gross undeveloped acres and two optional exploration test wells in two additional 640 gross undeveloped acre sections in the Citrus prospect. The farmee must drill one well in each of the three 640-acre sections in order to earn a working interest in that section. We will retain a royalty interest in each of those sections until payout of the exploration well at which time we have the option to convert our royalty interest to a 50% working interest. In addition, we will retain a 100% working interest in approximately 600 undeveloped gross acres in the Citrus prospect. In 2005, our development activities at Citrus were $0.1 million, a decrease of $5.5 million compared to 2004 when we drilled three successful wells.

Northwest Lost Hills

The Northwest Lost Hills #1-22 deep well, operated by Aera, began drilling in August 2001. The well was designed to evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reached a depth of approximately 21,000 feet. This drilling objective was achieved in August 2002 after substantial delays and cost overruns resulting from difficult drilling conditions. While drilling the well, we encountered several high-pressure intervals which indicated the presence of natural gas and set casing in preparation for testing. In 2003, the well was temporarily suspended pending the identification of one or more partners to share the costs of the testing program. In August 2005, we concluded a farm-out of one-third of our 42% working interest to Aera to complete and test the Northwest Lost Hills # 1-22 deep gas well at no additional cost to Ivanhoe. Our share of completion equipment, of approximately $1.0 million, previously purchased by the joint venture partners, was used in the completion of the well including a 4 1/2-inch liner, which was run over the open hole to a depth of 21,000 feet. The well was tested in January 2006 and in two tests flowed a non-commercial rate of 400 Mcf/d and 5,000 Bbls/d of water. Aera recommended abandoning the well, with which we concur, and abandonment operations will commence in the third quarter of 2006 at an anticipated net cost to us of $0.7 million. We have no further plans to explore in this prospect.

Other California Prospects

Knights Landing

In February 2004, we farmed into the Knights Landing field, which is a 15,700 gross-acre block located in the Sutter and Yolo counties in northern California, by purchasing a 50% working interest in four previous discoveries in the contract area and funding gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. In 2004, we drilled nine new exploratory wells to earn a 50% working interest after payout in any new discoveries, which resulted in three successful completions and six dry holes. Three of these new wells were successful and by April 2005 had been tied into the existing pipeline system and were on production. In December 2004, we reached an agreement with the operator of the field to purchase its interest in the field, increasing our working interests in the field and 11 existing producing natural gas wells to between 80% and 100%. In late 2005, a 3-D seismic data program was acquired over 25 square miles covering our Knights Landing acreage block. We completed our seismic acquisition program in December 2005 and have initiated interpretation of the seismic data. We expect to complete processing and interpretation of the seismic data by the end of the second quarter of 2006 and to recommence drilling in the third quarter of 2006. 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. We spent $2.5 million on development activities at Knights Landing in 2005 on seismic plus the costs to hook up the three successful exploration wells drilled in 2004, a decrease of $4.6 million compared to 2004. We reached peak average production from our Knights Landing gas wells of 185 gross Boe/d (110 net Boe/d) in the third quarter of 2005 but by the end of 2005, production from the Knights Landing wells had been fully depleted in all but one well, which was producing 12 gross Boe/d (7 net Boe/d).

North Salt Creek

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 and are the operator. The initial well resulted in a dry hole. A second prospect, North Salt Creek #1, was drilled to 2,500 feet on the acreage in 2005 and encountered 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. Drilling of two follow-up wells was completed in the fourth quarter of 2005. Multiple targets were encountered in both of these wells. Production testing indicated the reservoir contains heavy 12° API oil and will likely require steam to produce commercially. We are in the process of obtaining permits to test steam these wells. Our expenditures for 2005 totaled $0.5 million and additional drilling to develop this field is planned for 2006.

North Yowlumne

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. We hold a 12.5% working interest in this prospect and have farmed out an 87.5% interest in the initial well and prospect. In the event of a discovery, we will own a 56.25% working interest in the well after payout. Results of the well will be known during the first quarter of 2006. We own an interest in approximately 6,900 gross acres in the prospect.

Wyoming

LAK Ranch

In January 2004, we signed farm-in and joint operating agreements with Derek Resources (USA), Inc. (**Derek**) for the joint development of the LAK Ranch field, a thermal recovery/horizontal well oil project in Weston County, Wyoming. The LAK Ranch field covers approximately 7,500 gross acres in Wyoming s Powder River basin.

We are the operator of the project and earned an initial 30% working interest by financing the capital cost of the pilot phase. Following the pilot phase, we will have the option to increase our working interest to 60% by providing additional capital toward the initial development phase for a total of $5.0 million, including the amounts spent on the pilot phase. Thereafter, all future capital expenditures are to be shared on a working-interest basis. Should we elect not to proceed beyond the pilot phase our working interest will be reduced to 15% and Derek will become the operator. At the end of 2005 our working interest was 43%.

Prior to the farm-in agreement, Derek completed a steam assisted gravity drainage horizontal well pair to a depth of 1,000 feet and 1,800 feet into the Newcastle Sand formation. Surface steam-injection and oil-recovery equipment was installed. Extensive testing indicates that, because of the viscosity of the oil, production can be expected to respond favorably to the application of continuous heat through steam injection. Facility modifications for the pilot phase were completed in the second quarter of 2004 to enable steam injection in the producing horizontal well.

The ultra-high resolution 3-D seismic survey needed to better define the optimum reservoir development locations was completed in December 2004 with results evaluated during the second quarter of 2005. In addition, one vertical well was drilled in the first quarter of 2005 for data collection purposes. We used the data from the 3-D seismic survey to plan and drill three vertical injection wells and test the potential of continuous steam injection. We commenced continuous steaming in the fourth quarter of 2005. An early production response was realized from this injection, with oil rates increasing from 10 to 45 bopd. We plan continuous steam injection throughout 2006, while monitoring the production response. Based on observed production and temperature responses, we will evaluate the potential to expand the pilot project.

Following completion of the pilot phase, the development phase would include additional horizontal production wells, new steam-injection and extension of surface facilities. The performance of the pilot phase will dictate the development timing. We invested $1.2 million in LAK Ranch in 2005, a decrease of $0.8 million compared to 2004. We expect to reach a decision regarding the development phase by the fourth quarter of 2006.

China

Dagang

Our producing property in China is a 30-year production-sharing contract with China National Petroleum Corporation (**CNPC**), covering an area of 22,400 gross acres divided into six 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%. 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 for common shares in Ivanhoe 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 acquired Richfirst s 40% working interest.

The production-sharing contract stipulates that we have the right to market our oil domestically or export it, sell our product in U.S. dollars and receive world market prices for our product. We are currently selling our crude oil to CNPC at a three-month rolling average price of Cinta crude oil, which is currently averaging approximately $3.00 per barrel less than the West Texas Intermediate (**WTI**) price. Cinta is an Indonesian crude that is traded daily on the international oil market.

All petroleum producers in China pay a value added tax of 5% on oil production. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang field exceeds 500,000 tonnes per annum. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. 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.

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. In 2004, we drilled 19 development wells and in 2005 we drilled and completed an additional 19 wells, had one well awaiting completion and recompleted 6 existing wells. We incurred $23.8 million for our development activities in the Dagang field, in 2005, an increase of $3.8 million compared to 2004.

The year-end 2005 gross production rate was 2,310 Bopd compared to 1,655 Bopd at the end of 2004. Review of test results in the most northerly block of the Dagang field confirmed the presence of significant faulting and poor reservoir continuity, eliminating the potential for economic development in that block. By the end of 2005, we had drilled a total of 39 development wells, as compared to the estimated 115 wells set out in the approved ODP. We suspended drilling to allow for detailed evaluation of well productivity and production decline performance. In the fourth quarter of 2005, we reached agreement with CNPC to reduce the overall scope of the ODP to approximately 60 wells. Subsequent to that agreement, and as a result of lower than anticipated well productivity on the most recent wells, a review of our investment and return potential was undertaken. Our fracture stimulation program was expanded to allow a quicker evaluation of the potential of the blocks being developed. We continue to conduct technical reviews and evaluate the results of our stimulation program to provide the information necessary to make critical decisions on resuming our drilling program.

As provided for in the production-sharing contract, if CNPC requests us to resume development operations within a reasonable period of time, and we fail to resume operations within that time frame, CNPC has the right to request us to give up our rights in the oil field. We are currently in discussions with CNPC, based on our evaluations and further economic studies of productivity of the field, as to the scope of the final ODP. We expect to resolve this with CNPC in the second quarter of 2006. Should there be a disagreement between CNPC and ourselves as to the final ODP scope, there are arbitration provisions in the contract that allow us to settle matters such as this.

Sichuan Basin

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 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.

During the first phase of exploration, which expired in December 2005, we were to complete a minimum work program consisting of reprocessing approximately 1,250 miles of seismic data, completing approximately 300 additional miles of new seismic lines and drilling at least 23,000 feet. Upon completion of the first phase, we must relinquish up to 30% of the Zitong block. From 2003 to 2005, we reprocessed approximately 1,550 miles of existing seismic data and acquired approximately 700 miles of new seismic data plus interpretation of all the seismic data. In the second quarter of 2005, we drilled our first well, Dingyuan 1, to a depth of approximately 9,000 feet. The well was not commercially viable and cement plugs were set that will allow us to use the surface location and re-enter the well bore for a potential directional hole. During 2005, we spent $4.0 million to acquire and process seismic data and $2.9 million to drill our first well, Dingyuan 1 compared to $6.9 million spent in 2004 to complete the acquisition, processing and interpretation of our seismic program.

In December 2005, we were granted an extension of the first phase to May 31, 2006 provided the second exploration well is spud before May 1, 2006. If the second exploration well is spud before May 1, 2006 but we are unable to complete the drilling operation before May 31, 2006, CNPC will grant a further six-month extension to complete the drilling operation.

In January 2006, we finalized a farm-out agreement with Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**). Mitsubishi will pay us $4.0 million for a 10% interest in the Zitong block, subject to approval from the relevant Chinese authorities. After the drilling of a second exploration well in 2006, which is expected to substantially satisfy our work commitment for the first phase, we will evaluate the results and make an election at that time as to our decision, along with Mitsubishi, to enter into the next three-year exploration phase.

If we elect to participate in the second phase, we must complete a minimum work program consisting of new seismic lines totaling approximately 200 miles and drill approximately 23,000 feet, with estimated minimum expenditures for the program of $16 million. Following the completion of phase two, we must relinquish all of the property except any areas identified for development and production. If we elect to enter into phase two, we must complete the minimum work program or we will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase.

If we identify a field for development and/or production, the parties will divide the participating interest in the project, with CNPC entitled to fund and take up to 51% of the participating interest and Mitsubishi and us the remaining 49%. Once commercial production commences, we will recover annual exploration, development and operating costs from up to 60% of gross oil production and 70% of gross natural gas production. After annual cost recovery, we are entitled to production equaling our participating interest, subject to certain additional rights of the Chinese government. Assuming we, along with Mitsubishi, hold a 49% participating interest, we will be entitled to approximately 75% of production initially, declining to approximately 45% after full exploration and development cost recovery.

CNPC retains the rights to production from six existing wells located on the Zitong block. We can drill new wells on the same structure as those tapped by the existing wells, but our wells must be no closer than 3,280 feet from the existing wells.

CITIC Alliance

In October 2002, we entered into an agreement with CITIC Energy Ltd. (**CITIC Energy**) to form a strategic alliance to seek out and develop oil and gas projects in China and around the world. CITIC Energy is a subsidiary of CITIC, a major Chinese state-owned enterprise that holds interests in a wide range of industries.

In April 2003, we entered into a further agreement with CITIC Energy that enables both companies to form a global strategic alliance to investigate, explore and develop oil, natural gas, metallurgical coal, liquefied natural gas and GTL projects in China and around the world, to help supply China s future energy requirements. The agreement builds upon the initial partnership formed between the two companies in October 2002 and follows discussions both between the two companies and with asset owners of potential projects in China and in other parts of the world.

OTHER ENHANCED OIL RECOVERY PROJECTS

Enhanced oil recovery, also referred to as tertiary recovery, refers to a variety of processes to increase the amount of oil removed from a reservoir, typically by injecting a liquid (e.g., steam, surfactant) or gas (e.g., nitrogen, carbon dioxide). EOR techniques are generally utilized after oil and gas production levels decline from primary recovery and secondary recovery (e.g. waterflood) methods. The most successful by far of the EOR methods is steam injection.

Iraq

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 17.9 API heavy oil at a depth of about 1,000 feet.

We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the RTP™ Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR and heavy oil processing methods to establish economically recoverable volumes at the Qaiyarah oil field.

The reservoir assessment has been completed and various recovery methods have been evaluated. Facility design work is currently progressing and once complete, an economic evaluation will follow. If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. We expect to submit our proposal to the Iraq Ministry of Oil in the second half of 2006. The Iraq Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

We invested $1.7 million and $0.2 million in 2005 and 2004, respectively, on the Qaiyarah heavy oil field project. In addition, we invested $1.1 million and $1.8 million in 2005 and 2004, respectively, on other projects in Iraq including submission of four bids for the engineering, design and procurement of oil production facilities and EOR development projects. Our bids are still under consideration by the Iraq Ministry of Oil.

Colombia

In late 2004, we signed an MOU with Ecopetrol S.A. (**Ecopetrol**) for a study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia, located about 75 miles southeast of Bogotá in the Central Llanos Basin. We did not meet the company-size requirements that Ecopetrol specified in its final bidding qualifications for the Llanos Basin Heavy Crude Project , which included the Castilla and Chichimene fields and in the third quarter of 2005 we wrote down our $0.3 million investment in this project. We continue to review the potential for other heavy oil upgrading opportunities in Colombia.

EMPLOYEES

As at December 31, 2005, we had 153 employees. None of our employees are unionized.

RESERVES, PRODUCTION 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. 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.

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		
	2005	2004	2003	2005	2004	2003
Crude Oil and Natural Gas ($/Boe)						
U.S	$ 44.01	$ 34.66	$ 25.69	$ 15.64	$ 11.76	$ 10.87
China	$ 49.97	$ 36.11	$ 28.41	$ 8.27	$ 8.14	$ 13.71

The following tables 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.

	2005				2004				2003			
	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.	87(1)	69.3(1)	3(1)	1.5(1)	84(2)	67.2(2)	13	11.7	76	59.9	1	0.5
China	43	21.2			21	10.3(3)			9	7.4		

(1) After giving effect to 10.8 net (12 gross) producing wells shut in or converted to disposal wells in 2005.

(2) After the sale of 0.8 net (2 gross) Sledge Hamar wells in December 2004 and the purchase of 8.2 net (9 gross) Knight s Landing wells partially in April of 2004 and the remainder (including an increase in the working interest of the existing wells) in

December of 2004.

(3) After giving effect to the 40% farm-in 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**					
	2005		**2004**		**2003**		**2005**		**2004**		**2003**	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
U.S.	1.5	0.2	0.4	3.0				1.8(1)	1.4	4.0		
China								1.0				
Total	1.5	0.2	0.4	3.0				2.8	1.4	4.0		

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

Development

	Productive Wells						**Dry Wells**					
	2005		**2004**		**2003**		**2005**		**2004**		**2003**	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
U.S.	1.0		7.3(1)		17.0				2.0		2.0	
China	10.8		7.9									
Total	11.8		15.2		17.0				2.0		2.0	

(1) Includes 0.3 (1 gross) net producing wells acquired as a result of the farm-in to LAK Ranch.

Wells in Progress

At the end of 2005, 2004 and 2003 we had 1.1 (3 gross), 2.9 (6 gross) and 2.8 (5 gross) net wells, respectively, which were either in the process of drilling or suspended.

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2005. 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.	14,055	6,176	104,387	31,838
China (1)	2,969	1,461	888,924	884,280

(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.

The following table sets out estimates of our share of proved reserves in respect of our U.S. and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2005. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and Gilbert Laustsen Jung Associates Ltd., respectively.

	Our Share		Our Share of Before Tax Cash Flows In Thousands of U.S. Dollars Discounted at:			Our Share of After Tax Cash Flows In Thousands of U.S. Dollars Discounted at:		
	Oil (Mbbl)	**Gas (MMcf)**	**0%**	**10%**	**15%**	**0%**	**10%**	**15%**
Net Proved Reserves (1)								
U.S.	1,272	1,685	$ 47,829	$ 32,174	$ 28,128	$ 47,829	$ 32,174	$ 28,128
China	1,300		55,569	44,114	39,997	53,985	43,299	39,397
	2,572	1,685	$ 103,398	$ 76,288	$ 68,125	$ 101,814	$ 75,473	$ 67,525

(1) **Net Proved Reserves** are our share of the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. See the Supplementary Disclosures about Oil and Gas Production Activities , which follow the notes to our financial statements set forth in Item 8 of this Annual

Report on Form 10-K.

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 U.S. disclosure standards. 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 U.S. standards for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with U.S. disclosure 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 U.S. disclosure 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 SFAS No. 69. Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the U.S. 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 calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecasted prices;

- the SEC mandates disclosure of proved and proved producing 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 U.S. disclosure standards and NI 51-101 requirements.

ADDITIONAL FACTORS AFFECTING THE BUSINESS

See also Item 7 of this Form 10-K.

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. See Risk Factors .

Environmental Regulations

Our conventional oil and gas and EOR 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. See Risk Factors . 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.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

Environmental Provisions

As at December 31, 2005, a $1.7 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S. and $0.1 million for the removal of the RTP™ CDF and restoration of the Aera site occupied by the RTP™ CDF. The future cost of these obligations is estimated at $2.2 million and $0.1 million for the U.S. wells and RTP™ 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 2005, we added $1.0 million and $0.1 million to our provision for future site restoration and plugging and abandonment of U.S. wells and RTP™ CDF, respectively.

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 in the U.S., often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

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 are not able to guarantee the successful commercial development of the RTP ™ Technology.

To date, no commercial-scale RTP™ Plants have been constructed using the RTP™ Technology and, therefore, the process has not been proven to be financially viable on a commercial scale. Other developers of competing heavy-oil processing technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude joint venture or production-sharing contracts using the RTP ™ Technology.

We have signed an MOU to study the economic feasibility of RTP heavy oil processing facilities in Iraq but we can give no assurances as to when or if we will be able to conclude joint ventures or production-sharing contracts employing RTP™ Technology.

We are not able to guarantee the successful commercial development of our licensed GTL technology.

To date, no commercial-scale GTL plants have been constructed using the Syntroleum Process and, therefore, the process has not been proven on a commercial scale. Other developers of GTL technology have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude a GTL development and production-sharing contract.

To date, we have been unsuccessful in concluding a GTL development and production-sharing contract and we can give no assurances as to when or if we will be able to conclude a contract in any of the countries where we are now, or will be, exploring GTL project opportunities.

Our efforts to commercialize the Syntroleum Process and the RTP ™ Technology may give rise to claims of infringement upon the patents or proprietary rights of others.

We own licenses to employ the Syntroleum Process and the RTP™ Technology process but we may not become aware of claims of infringement upon the patents or rights of others in these respective technologies until after we have made a substantial investment in the development and commercialization of projects utilizing these licensed technologies. Third parties may claim that the technologies we license have infringed 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 affected technologies. 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 affected technologies. 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 affected licensed 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 GTL or heavy oil processing technologies competitive with the Syntroleum Process and the RTP™ Technology that we license, may have significantly more resources to spend on litigation.

Technological advances could significantly decrease the cost of upgrading petroleum and, if we are unable to adopt or incorporate technological advances into our operations, the RTP ™ 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 RTP™ Technology, 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 RTP™ 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 RTP™ Technology facilities to become uncompetitive.

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 RTP™ 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.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may harm our financial condition.

We will be required to make substantial capital expenditures far beyond our existing capital resources to develop a GTL, EOR or RTP™ Technology project, to exploit our existing reserves and to discover new oil and gas reserves. Historically, we have relied, and continue to rely, on external sources of financing to meet our capital requirements to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. We plan to obtain the future funding we will need through debt and equity markets or through project participation arrangements with third parties, 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. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties 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 have a history of losses and must generate greater revenue to achieve profitability.

We commenced operations in 1997 and have been involved in three start-up situations in Russia, China and the U.S. Like most start-up companies we have incurred losses during our start-up activities. Our current cash flows alone are insufficient to fund our business plans, necessitating further growth and funding for implementation. We may be unable to achieve the needed growth to obtain profitability, fund debt repayments and related interest payments and may fail to obtain the funding that we need when it is required.

Conflict in the Middle East may hamper our GTL and EOR project objectives.

Ongoing tensions and conflict in the Middle East could harm our business by making it difficult or impossible to continue our pursuit of GTL and EOR projects in the region or to obtain financing for projects we do succeed in obtaining. It is impossible to predict the occurrence of such events, how long they will last, the economic consequences of the conflict for the energy industry, regionally and globally, and how our business might be affected over the longer term.

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.

You should not unduly rely on reserve information because reserve information represents estimates.

Reserve estimates involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to, geological characteristics of the reservoir structure, reservoir fluid properties, the size and boundaries of the drainage area and reservoir pressure and the anticipated rate of pressure depletion.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties, but the probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves usually differ from estimates.

Reserve estimates also require numerous assumptions relating to operating conditions and economic factors including, among others, the price at which recovered oil and natural gas can be sold, the costs of recovery, prevailing environmental conditions associated with drilling and production sites, availability of enhanced recovery techniques, ability to transport oil and natural gas to markets and governmental and other regulatory factors, such as taxes and environmental laws.

A negative change in any one or more of these factors could result in quantities of oil and natural gas previously estimated as proved reserves becoming uneconomic. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production thereof commercially impracticable. The risk that a decline in price could have that effect is magnified in the case of reserves requiring sophisticated or expensive production enhancement technology and equipment, such as some types of heavy oil. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also affect the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and expected future net cash flows therefrom prepared by different independent engineers, or by the same engineers at different times, may vary substantially.

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 document. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of 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.

We cannot guarantee the successful commercialization of our exploration activities.

We have exploration and development projects in the U.S. and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically recoverable volumes.

We might not be successful in acquiring and developing new prospects and our exploration and development properties may not contain any significant proved reserves.

Our future exploration and development success depends upon our ability to find, develop and acquire additional economically recoverable oil and natural gas reserves. The successful acquisition and development of oil and gas properties requires proper forecasting of recoverable reserves, oil and gas prices and operating costs, potential environmental and other liabilities and productivity of new wells drilled.

Estimates of cost to explore, develop and produce are inherently inexact. As a result, we might not recover the purchase price of a property from the sale of production from the property, or might not realize an acceptable return from properties we acquire. Our estimates of exploration, development and production costs can be affected by such factors as permitting regulations and requirements, weather, environmental factors, unforeseen technical difficulties and unusual or unexpected formations, pressures and work interruptions.

Exploration and development involves significant risks. Few wells which are drilled are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proved reserves, and we cannot assure you that sufficient commercial quantities of oil and gas deposits will be discovered to enable us to recover our exploration and development costs and sustain our business.

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

Some of our properties are held under licenses and leases and working interests in licenses and leases. If we, or the holders of the licenses or leases, fail to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may harm our business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are unable to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

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.

Crude oil and natural gas prices are volatile.

Fluctuations in the prices of oil and natural gas will affect many aspects of our business, including our revenues, cash flows and earnings; our ability to attract capital to finance our operations; our cost of capital; the amount we are able to borrow and the value of our oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or agreements between members of the OPEC can affect world oil supply and prices. Any material decline in prices could result in a reduction of our net production revenue and overall value. The economics of producing from some wells could change as a result of lower prices and as a result, we could elect not to produce from certain wells. Any material decline in prices could also result in a reduction in our oil and natural gas acquisition and development activities.

In addition, a material decline in oil and natural gas prices from historical average prices could adversely affect our ability to borrow and to obtain additional capital on attractive terms.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

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 21% 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 and technical personnel. Messrs. David Martin and E. Leon Daniel, in particular, have extensive experience in oil and gas operations throughout the world. 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 AND RELATED STOCKHOLDER MATTERS

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.$)

	2005				2004			
	4th Qtr	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**
High	2.00	2.50	2.95	3.34	3.20	2.33	3.06	4.28
Low	.99	1.97	1.98	2.04	2.03	1.22	2.08	1.96

TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2005				2004			
	4th Qtr	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**
High	2.32	3.06	3.60	4.02	3.90	3.00	4.15	5.49
Low	1.16	2.30	2.52	2.52	2.56	1.62	2.88	2.63

On December 31, 2005, the closing prices for our common shares were $1.06 on the NASDAQ Capital Market and Cdn. $1.23 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. 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.

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 a board comprised of a majority of independent directors, there is no legal requirement in Canada that mandates a board comprised of a majority of independent directors. Our board of directors consists of 5 individuals who are independent and 5 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.

Enforceability of Civil Liabilities

We were organized under the laws of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling persons and 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 persons, 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 persons, 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 persons or experts named in this Annual Report on Form 10-K.

Holders of Common Shares

As at December 31, 2005, a total of 220,779,335 of our common shares was issued and outstanding and held by 222 holders of record with an estimated 36,297 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, 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 2006 is Cdn.$265 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) (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%.

Sales of Unregistered Securities

During the year ended December 31, 2005, we issued securities, which were not registered under the Securities Act of 1933 (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. FIVE YEAR SUMMARY OF 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 .

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

December 31,

(stated in thousands of U.S. dollars, except per share amounts)

	2005	2004	2003	2002	2001
Financial Position					
Total assets	240,877	118,486	106,574	107,088	104,003
Long-term debt	4,972	2,639	833	Nil	Nil
Shareholders equity	204,767	103,586	100,537	100,548	96,897
Common shares outstanding (in thousands)	220,779	169,665	161,359	144,466	139,267
Capital investments	43,301	46,454	15,391	18,828	40,504
Results of Operations					
Revenues	29,939	17,997	9,659	8,437	9,722
Net loss	13,512(1)	20,725(1)	30,179(1)	7,130(1)	21,122(1)
Net loss per share basic and diluted	0.07	0.12	0.20	0.05	0.16

(1) Includes asset write-downs and provisions for impairment of $5.6 million, $16.6 million, $23.3 million, $2.4 million and $14.0 million for 2005, 2004, 2003, 2002 and 2001, respectively. See Notes 4 and 15 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 only material differences between Canadian and U.S. GAAP, which affect our financial statements are as follows:

adjustment for the reduction in stated capital in 1999,

increase in the ascribed value of shares issued for the acquisition of U.S. royalty interests in 1999 and 2000,

net additional impairment provision for our China oil and gas properties in 2001 and 2005, net of depletion expense,

net additional impairment provision for our U.S. oil and gas properties in 2004 and 2005, net of depletion expense,

net additional expense from 2001 to 2005 in connection with development costs for our GTL and EOR projects, and

reduction in the net losses from 2002 to 2005 for stock based compensation accounted for under the intrinsic value method for U.S. GAAP.

For the U.S. GAAP reconciliations, see Note 23 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, (stated in thousands of U.S. dollars, except per share amounts)				
	2005	**2004**	**2003**	**2002**	**2001**
Financial Position					
Total assets	224,935	105,791	94,024	91,921	90,219
Shareholders equity	188,825	90,892	87,987	85,279	83,113
Results of Operations					
Net loss	14,972	19,696	27,086	8,202	36,264
Net loss per share basic and diluted	0.07	0.12	(0.18	0.06	0.28

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 INCLUDED IN THIS ANNUAL REPORT ON FORM 10-K. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GAAP IN CANADA. THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 23 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.

NOTE: CANADIAN INVESTORS SHOULD READ THE SPECIAL NOTE TO CANADIAN INVESTORS ON PAGE 14 WHICH HIGHLIGHTS DIFFERENCES BETWEEN OUR RESERVE ESTIMATES AND RELATED DISCLOSURES THAT ARE OTHERWISE REQUIRED BY CANADIAN REGULATORY AUTHORITIES.

Executive Overview of 2005 Results

Although our 2005 results were improved over those a year ago, we were not profitable for the year. Revenue for 2005 increased by 66% or $11.9 million to $29.9 million as a result of a 34% increase in production in China and a 19% production increase in the U. S.

as well as from increased oil and gas prices in both regions. However, this improvement was offset in part by $2.9 million of increased costs related to our business and product development activities, including the operation of our heavy oil RTP™ CDF and by a $7.0 million increase in depletion and depreciation. We impaired our China oil and gas properties by $5.0 million during 2005 compared to a $16.3 million impairment of our U.S. oil and gas properties in 2004.

Our single goal continues to be to build our oil and gas reserve base and production. In executing this plan, we believe that our most valuable assets are our licensed patented technologies and our employees with their unique technical experience. Our immediate priority is to build on the positive test results achieved at our heavy oil RTP™ CDF located in the San Joaquin Basin, California and to establish partnerships with owners of heavy oil reserves where we will build, own and operate commercial heavy-to-light oil processing facilities that use our RTP™ Technology.

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

	Year ended December 31,		
	2005	**2004**	**2003**
Net loss	13,512	20,725	30,179
Net loss per share	0.07	0.12	0.20
Average annual production (Mboe/d)	1,738	1,376	979
Capital investments	43,301	46,454	15,391
Cash flow (deficit) from operating activities	9,358	4,032	(1,522)

Financial Results Year to Year Change in Net Loss

The following provides an analysis of our changes in net losses for the year ended December 31, 2005 when compared to the same period for 2004 and for the year ended December 31, 2004 when compared to the same period for 2003:

	2005 vs. 2004	**2004 vs 2003**
Net Losses for 2004 and 2003	$ 20,725	$ 30,179
Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	4,334	4,534
Oil and gas prices	7,671	3,442
Hedge loss		250
Less: Operating costs	(2,530)	(780)
	9,475	7,446
General and administrative	(1,589)	405
Business and product development	(2,893)	(582)
Net interest	(881)	(36)
Total Cash Variances	4,112	7,233
Non-Cash Items:		
Depletion and depreciation	(6,965)	(3,653)

Stock based compensation	(837)	(800)
Write downs of GTL and EOR investments	(386)	3,071
Impairment of oil and gas properties	11,350	3,650
Other	(61)	(47)
Total Non-Cash Variances	3,101	2,221
Net Losses for 2005 and 2004	$ 13,512	$ 20,725

Our net loss for 2005 was $13.5 million ($0.07 per share) compared to our net loss in 2004 of $20.7 million ($0.12 per share). The decrease in our net loss from 2004 to 2005 of $7.2 million was due mainly to an $11.4 million reduction in impairment of our U.S. and China oil and gas properties and a $9.5 million increase in net operating revenues. This was partially offset by a $7.0 million increase in depletion and depreciation expense, a $5.3 million increase in general administrative and business and product development expenses including stock based compensation, a $0.9 million net increase in interest and financing costs and a $0.4 million increase in write downs of our GTL and EOR investments.

Our net loss for 2004 was $20.7 million ($0.12 per share) compared to our net loss in 2003 of $30.2 million ($0.20 per share). The decrease in our net loss from 2003 to 2004 of $9.5 million was due mainly to a $3.7 million reduction in impairment of our U.S. oil and gas properties, $3.1 million decrease in write-downs of our GTL investments and a $7.4 million increase in net operating revenues. This was partially offset by a $3.7 million increase in depletion and depreciation expense and a $1.0 million increase in general administrative and business and product development expenses including stock based compensation.

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

Net Operating Revenues

Production Volumes 2005 vs. 2004

Net production volumes in 2005 increased 26% from 2004 due to 34% and 19% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $4.3 million.

China

Net production volumes increased 48% at the Dagang field for 2005. This increase in production volumes accounted for $3.3 million of our increase in revenues for 2005. We placed 22 new wells on production during 2005 bringing to 43 the total number of Dagang wells on production, or available for production. In 2005, we initiated a stimulation program in the northern blocks of the field where we were experiencing less than expected results. We stimulated 13 of our northern block wells and added, on average, incremental production per well of 65 gross Bopd (30 net Bopd), with current production levels of 85 gross Bopd (40 net Bopd) per well. We continue to evaluate production results of other northern block wells to identify additional stimulation candidates. As at December 31, 2005, 39 wells were on production and producing 2,310 gross Bopd (1,080 net Bopd). This is a 40% increase in production rates compared to 1,655 gross Bopd (774 net Bopd) as at December 31, 2004.

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 28% for 2005 compared to the same period in 2004.

U.S.

The 19% increase in U.S. production volumes for 2005 was due mainly to a 286% increase in production at our Knights Landing gas field in northern California. In April 2005, three Knights Landing wells that were drilled and completed in 2004 were connected to a gas sales line and placed on production. As at December 31, 2005, production from the Knights Landing wells had been fully depleted in all but one well, which was producing 12 gross Boe/d (7 net Boe/d) compared to average peak production rates of 411 gross Boe/d (267 net Boe/d) reached in the third quarter of 2005 resulting in a decrease in production volumes of 30.5 gross Mboe (19.9 net Mboe) for the fourth quarter of 2005.

Our production volumes at Citrus for 2005 were up 10% compared to 2004, however, production volumes for the fourth quarter of 2005 were down 7.9 gross Mboe (6.1 net Mboe) from average peak production levels reached in the fourth quarter of 2004 reflecting a natural decline in the wells. As at December 31, 2005, we were producing 77 gross Boe/d (60 Boe/d net) at Citrus compared to 198 gross Boe/d (159 Boe/d net) as at December 31, 2004.

Our production at South Midway increased 7% for 2005 primarily as a result of our continuous steam injection program in the southern expansion of South Midway, which has more than offset the natural decline in production from the wells in the primary section of South Midway. Additionally, in 2005 we drilled one in-fill well in the southern expansion and one successful exploration well adjacent to the primary area of South Midway, which contributed to the increase in production. As at December 31, 2005, we were producing 536 gross Boe/d (499 net Boe/d) at South Midway compared to 542 gross Boe/d (504 net Boe/d) as at December 31, 2004.

The decrease in production volumes in other U.S. properties for 2005 was primarily due to the natural decline in production rates from our Spraberry field in West Texas and as a result of the sale of our interest in the Sledge Hamar property in the fourth quarter of 2004.

We consider LAK Ranch to be a pilot program and as such offset net operating revenues from the field with our capital investment in LAK Ranch. Accordingly, revenues, operating costs and production volumes from LAK Ranch are not included in this analysis.

The following is a comparison of changes in production volumes for the year ended December 31, 2005 when compared to the same period in 2004:

	Years ended December 31, Net Boe s		Percentage
	2005	**2004**	**Change**
China:			
Dagang	282,582	190,309	48%
Daqing	32,236	44,626	-28%
	314,818	234,935	34%
U.S.:			
South Midway	196,428	183,875	7%
Citrus	34,257	31,008	10%
Knights Landing	57,106	14,786	286%
Others	31,883	38,945	-18%
	319,674	268,614	19%
	634,492	503,549	26%

Production Volumes 2004 vs. 2003

Net production volumes in 2004 increased 41% from 2003 due to 63% and 26% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $4.5 million.

China

Net production volumes at the Dagang field increased 46% in 2004 despite the farm-out of 40% of our interest in June 2004. We commenced development of the Dagang field in late 2003 and by the end of 2004 we drilled 19 wells of which 16 were completed and placed on production. As at December 31, 2004, our gross production rate was 1,655 Bopd (774 net Bopd) compared to 505 Bopd at the end of 2003 (236 net Bopd adjusted for a 40% farm-out for comparability to 2004). As at December 31, 2004, a total of 22 wells were producing at our Dagang field. Additionally, we benefited from the expanded Daqing field development program and the royalty interest we retained after the sale of our working interest in this field in 2002 as our royalty share of production increased 224% from 2003.

U.S.

Net production volumes in the U.S. increased 26% in 2004 mainly from the Citrus and Knights Landing fields, both of which started production in 2004, as well as from our development program at South Midway. We farmed into the Knights Landing gas field in northern California in February 2004 with a 50% working interest in 4 producing natural gas wells and in December 2004 improved the potential of our California properties by increasing our working interest to between 80% and 100% in 12 Knights Landing natural gas wells capable of production and selling our interest in the Sledge Hamar field. We are the operator of the Citrus field and have a 100% working interest before payout in three Citrus wells, which were completed and placed on production in 2004. We saw increased production rates from our successful drilling and steaming operations at our South Midway field where we drilled 19 producing wells from 2003 to 2004. As at December 31, 2004, we were producing from 95 wells in the South Midway, Spraberry, Citrus, and Knights Landing fields at gross rates of production of approximately 1,320 Boe/d (920 net Boe/d).

The following is a comparison of changes in production volumes for the year ended December 31, 2004 when compared to the same period in 2003:

	Years ended December 31, Net Boe s 2004	2003	Percentage Change
China:			
Dagang	190,309	130,651	46%
Daqing	44,626	13,771	224%
	234,935	144,422	63%
U.S.:			
South Midway	183,875	169,858	8%
Citrus	31,008		100%
Knights Landing	14,786		100%
Others	38,945	42,962	-9%
	268,614	212,820	26%
	503,549	357,242	41%

Oil and Gas Prices 2005 vs. 2004

Oil and gas prices increased 33% per Boe in 2005 generating $7.7 million in additional revenue as compared to 2004. We realized an average of $49.97 per Boe from our operations in China during 2005, which was an increase of $13.85 per Boe from 2004 prices and accounted for $4.5 million of our increase in revenues. From the U.S. operations, we realized an average of $44.01 per Boe during 2005, which was an increase of $9.35 per Boe and accounted for $3.2 million of our increased revenues.

Oil and Gas Prices 2004 vs. 2003

Oil and gas prices increased 32% per Boe in 2004 generating $3.4 million in additional revenue as compared to 2003. We realized an average of $36.11 per Boe from our operations in China during 2004, which was an increase of $7.70 per Boe from 2003 prices and accounted for $1.7 million of our increase in revenues. From the U.S. operations, we realized an average of $34.66 per Boe during 2004, which was an increase of $8.97 per Boe and accounted for $1.7 million of our increased revenues.

We entered into costless collar derivatives to hedge our cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. We realized losses of $0.3 million on these derivative transactions in 2003 but had no derivative contracts in place during 2005 or 2004.

Operating Costs 2005 vs. 2004

Operating costs for 2005 increased $2.5 million in absolute terms from 2004 or $1.91 on a per Boe basis.

<u>China</u>

Operating costs in China, including engineering support, increased 2% or $0.13 per Boe for 2005. Field operating costs increased $1.45 per Boe or 24% in 2005 primarily due to higher power costs, permanent land fees on producing wells, security costs and increased treatment and processing costs due to higher water production rates. These increases were partially offset by reductions in workover and maintenance costs. Engineering support for 2005 decreased $1.32 per Boe or 63% compared to 2004 resulting from the increase in production volumes from the Dagang field in relation to the level of support required to operate the field.

<u>U.S.</u>

Operating costs in the U.S., including engineering support and production taxes, increased 33% or $3.88 per Boe for 2005. Field operating costs increased $2.50 per Boe for 2005 due mainly to an increase in fuel costs incurred for the cyclic and continuous steam operations at South Midway. For 2005, we spent $3.70 per Boe or 32% of our total U.S.

field operating costs for fuel at South Midway compared to $1.71 per Boe or 19% of our total U.S. field operating costs in 2004 as a result of the increase in natural gas prices during 2005. However, these increases in natural gas prices for the steaming operations at South Midway were more than offset by the price increase per barrel of oil received from our South Midway production during 2005 as our net operating revenue at South Midway increased $6.46 per Boe from 2004. In addition, our field operating costs increased $1.10 per Boe for 2005 primarily as a result of workovers at Knights Landing to complete new zones in the existing wells as production from the lower zones depleted. Engineering support increased $0.99 per Boe for 2005 due mainly to the start up of production operations at Knights Landing, where we became the operator in December 2004, and due to the start up of continuous steaming operations in the southern expansion of South Midway. Production taxes were up $0.39 per Boe due mainly to a full year assessment of our property values at Citrus and Knights Landing during 2005 and an increase in ad valorem taxes at South Midway due to a refund received in 2004.

Operating Costs 2004 vs. 2003

Operating costs for 2004 increased $0.8 million in absolute terms from 2003 but decreased $1.96 on a per Boe basis.

China

Operating costs in China, including engineering support, decreased 41% or $5.57 per Boe for 2004 due mainly to an increase in production from the Dagang field in relation to the level of fixed field operating costs and engineering support required to operate the field and reduced well workover and power costs during 2004.

U.S.

Operating costs in the U.S., including engineering support and production taxes, increased 8% or $0.89 per Boe for 2004. Field operating costs increased $1.29 per Boe due mainly to an increase in fuel costs incurred for the cyclic steam operations in the southern expansion of South Midway, increased costs to treat hydrogen sulfide levels in the gas produced from the South Midway field and the start up of production operations at our Citrus, Knights Landing, and Sledge Hamar fields. This is partially offset by a reduction in workover costs at our South Midway and Spraberry fields from 2003. Engineering support increased $0.19 per Boe due mainly to the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004. Production taxes are down $0.59 per Boe due mainly to a retroactive reassessment of property values at South Midway, which led to a refund of prior ad valorem taxes paid and a reduction in assessed values.

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis, from 2003 to 2005 are detailed below:

	Year ended December 31,								
		2005			2004			2003	
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Net Production:									
Boe	319,674	314,818	634,492	268,614	234,935	503,549	212,820	144,422	357,242
Boe/day for the year	876	863	1,738	734	642	1,376	583	396	979
		Per Boe			Per Boe			Per Boe	
Oil and gas revenue	$ 44.01	$ 49.97	$ 46.97	$ 34.66	$ 36.11	$ 35.34	$ 25.69	$ 28.41	$ 26.79
Field operating costs	11.44	7.49	9.48	8.94	6.04	7.59	7.65	9.31	8.52
Production taxes	0.83		0.42	0.44		0.23	1.03		0.62
Engineering support	3.37	0.78	2.08	2.38	2.10	2.25	2.19	4.40	2.89
	15.64	8.27	11.98	11.76	8.14	10.07	10.87	13.71	12.03
Net operating revenue	28.37	41.70	34.99	22.90	27.97	25.27	14.82	14.70	14.76
Depletion	15.53	29.77	22.60	16.80	12.18	14.64	10.58	10.23	10.44
	$ 12.84	$ 11.93	$ 12.39	$ 6.10	$ 15.79	$ 10.63	$ 4.24	$ 4.47	$ 4.32

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, 2005 when compared to the same period for 2004 and for the year ended December 31, 2004 when compared to the same period for 2003 were as follows:

	2005 vs. 2004	2004 vs 2003
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ (1,116)	$ 216
U.S.	(188)	1,119
Corporate	(950)	(1,730)
	(2,254)	(395)
Less: stock based compensation	665	800
	$ (1,589)	$ 405

General and Administrative 2005 vs. 2004

China

General and administrative expenses related to the China operations increased $1.1 million for 2005 due to costs incurred associated with financing discussions for our Dagang field development project.

U.S.

General and administrative expenses related to U.S. operations, before allocations to capital and operating costs, increased $1.4 million for 2005 primarily due to increased labor costs, including non-cash stock based compensation of $0.5 million. This is partially offset by increased allocations of general and administrative expenses to capital investments and operating costs of $0.8 million and $0.4 million, respectively, due to the increased levels of administrative support required for our GTL and EOR projects and due to becoming the operator at Knights Landing in December 2004 and the start up of continuous steaming operations in the southern expansion of South Midway in 2005.

Corporate

General and administrative costs related to Corporate activities increased $1.0 million for 2005 due mainly to a $0.6 million increase in labor costs, including non-cash stock based compensation of $0.2 million, and a $0.6 million increase in professional fees incurred in the first half of 2005 to complete our first year of compliance with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002. This is a partially offset by a $0.2 million reduction in premiums for directors and officers liability insurance.

General and Administrative 2004 vs. 2003

China

General and administrative expenses related to the China operations, before allocations of costs to capital and operating costs, increased $0.4 million primarily due to increased labor costs and ramp up of administrative offices required to support the development and exploration activities initiated at the end of 2003. This is offset by increased allocations of general and administrative costs to capital investments and operating costs of $0.5 million and $0.1 million, respectively, primarily as a result of the development program and increased operations at our Dagang field.

U.S.

General and administrative expenses related to U.S. operations, before allocations to capital and operating costs, increased $0.8 million for 2004 primarily due to increased labor costs, including non-cash stock based compensation. This is offset by increased allocations of general and administrative to capital investments and operating costs of $1.5 million and $0.4 million, respectively, as a result of increased levels of exploration and development activities in the U.S. during 2004 and the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004.

Corporate

Corporate general and administrative expenses increased $1.7 million mainly due to $0.8 million incurred during 2004 to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, a $0.8 million increase in non-cash stock based compensation related to the issuance of stock options and other net increases such as higher costs for directors and officers liability insurance.

Business and Product Development

Our changes in business and product development, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2005 when compared to the same period for 2004 and for the year ended December 31, 2004 when compared to the same period for 2003 were as follows:

	2005 vs. 2004	2004 vs 2003
Favorable (unfavorable) variances:		
GTL	$ 164	$ (140)
EOR	(3,229)	(442)
	(3,065)	(582)
Less: stock based compensation	172	
	$ (2,893)	$ (582)

Business and Product Development 2005 vs. 2004

During 2005, much of the focus of our business and product development activities was on EOR opportunities, particularly related to heavy oil processing, which resulted in a $0.2 million reduction in expenses we incurred related to GTL activities. Of the $3.2 million increase in business and product development expenses for 2005 associated with EOR activities, $1.6 million, including $0.2 million for non-cash stock based compensation, was related to consulting fees and travel costs to develop opportunities for our RTP™ Technology in the U.S., Canada, Iraq and other countries in the Middle East. In addition, operating expenses of the RTP™ CDF to develop and identify improvements in the application of the RTP™ Technology are expensed as part of our business and product development activities and contributed $1.6 million to the increase in business and product development for EOR activities in 2005.

Business and Product Development 2004 vs. 2003

We incurred a higher level of business and product development costs during 2004 related to identification of new opportunities for our GTL and heavy oil processing technologies particularly in the Middle East and China resulting in increased business and product development costs of $0.6 million.

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 2005 vs. 2004

Depletion and depreciation increased $7.0 million in 2005, $3.8 million of which was due to the increase in depletion rates to $22.60 per Boe in 2005 compared to $14.64 per Boe in 2004 and $3.2 million was due to increased production volumes from 2004.

China

China s depletion rate for 2005 was $29.77 per Boe compared to $12.18 per Boe for 2004, an increase of $17.59 per Boe resulting in a $4.1 million increase in depletion expense for 2005. Our depletion rate for the fourth quarter of 2005 was $43.76 per Boe compared to $14.33 per Boe for the same period in 2004. These increases were due mainly to two factors:

- As noted in prior periodic reports on Form 10Q and in related shareholder communications, we have suspended new drilling activity at our Dagang field in order that we may assess production decline performances on recently drilled wells, as well as maximizing cash flow from these operations. As a result, we have reduced our estimate of the overall development program and our independent engineering evaluators, Gilbert Laustsen Jung and Associates, have revised downward their estimate of our proved reserves as at December 31, 2005.

- We impaired the cost of our first Zitong block exploration well, Dingyuan 1, resulting in $12.2 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 $2.4 million of the increase in depletion expense for 2005.

U.S.

The U.S. depletion rate for 2005 was $15.53 per Boe compared to $16.80 per Boe for 2004, a decrease of $1.27 per Boe resulting in a $0.3 million decrease in depletion expense for 2005. Our depletion rate for the fourth quarter of 2005 was $18.01 per Boe compared to $14.96 per Boe for the same period in 2004. Production volume increases in the U.S. resulted in a $0.8 million increase in our depletion expense for 2005.

Depletion and Depreciation 2004 vs. 2003

Depletion and depreciation increased $3.7 million in 2004, $1.6 million of which was due to the increase in depletion rates to $14.64 per Boe in 2004 compared to $10.44 per Boe in 2003 and $2.1 million was due to increased production volumes from 2003.

<u>China</u>

The China depletion rate for 2004 was $12.18 per Boe compared to $10.23 per Boe for 2003, an increase of $1.95 per Boe resulting in a $0.3 million increase in depletion expense for 2005. This increase was due mainly to a downward revision of our share of proved reserves at Dagang as a result of continued increases in oil prices from 2003 and additional anticipated increases in future development costs. During periods of increasing oil prices our share of proved oil reserves decreases, as fewer barrels of oil are required to recover our costs under our production-sharing contract with CNPC. Production volume increases in China accounted for $1.1 million of the increase in depletion expense for 2004.

<u>U.S.</u>

The U.S. depletion rate for 2004 was $16.80 per Boe compared to $10.58 per Boe for 2003, an increase of $6.22 per Boe resulting in a $1.3 million increase in depletion expense for 2005. Despite a $16.3 million impairment of our U.S. oil and gas properties in 2004, our depletion rate increased in 2004 primarily as a result of significant costs of finding and acquiring proved reserves at our Knights Landing and Citrus fields as estimated by our independent engineering evaluators, Netherland, Sewell & Associates, as at December 31, 2004. Production volume increases in the U.S. accounted for $1.0 million of the increase in depletion expense for 2004.

<u>Net Interest</u>

Net Interest 2005 vs. 2004

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. Interest expense and financing costs for 2005 increased $0.8 million in 2005 as a result of these convertible loans. In addition, interest income decreased $0.1 million during 2005.

Net Interest 2004 vs. 2003

Our interest expense and financing costs increased $0.2 million for 2004 as a result of a 3% financing fee incurred for a $6.0 million stand-by loan facility with interest at 8% per annum. This increase was mostly offset by an increase in interest income for 2004.

<u>Write-Down of GTL and EOR Investments</u>

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 GTL or EOR 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 GTL and EOR assets. For U.S. GAAP, all such costs are expensed as incurred.

Write-Down of GTL and EOR Investments 2005 vs. 2004

In 2005, we wrote down $0.3 million related to our GTL project in Bolivia and $0.3 million related to our MOU with Ecopetrol for the Llanos Heavy Basin Crude Project . We wrote down our investment in the GTL project in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant and our investment in the MOU with Ecopetrol as our Company did not meet the company-size requirements specified by Ecopetrol in their final bidding qualifications for the Llanos Basin Heavy Crude Project , which included the Castilla and Chichimene field developments. This compares to the write down of $0.3 million in 2004 for our investment in the Oman GTL project.

Write-Down of GTL and EOR Investments 2004 vs. 2003

In 2004, we wrote down our $0.3 million investment in the Oman GTL project as our opportunity to build a 45,000-barrel per day GTL fuels plant in Oman failed to materialize due to a lack of sufficient committed gas volumes. This compares to the $3.3 million write-down of our GTL investments in connection with negotiation costs incurred to construct and operate a GTL production facility in Qatar, which was terminated in 2003 without reaching a definitive agreement.

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 2005 vs. 2004

We impaired our China oil and gas properties by $5.0 million in 2005, compared to a $16.3 million impairment of our U.S. oil and gas properties in 2004. As a result of production decline performance and drilling results from the wells drilled in the northern blocks of the Dagang field, we reduced our estimate of the overall field development program and our independent engineering evaluators, Gilbert Laustsen Jung and Associates, have revised downward their estimate of our proved reserves as at December 31, 2005. Additionally, we impaired 70% of our costs incurred in the Zitong block due to an unsuccessful first exploration well resulting in those costs, equal to $12.2 million, being included with the carrying value of proved properties for the ceiling test calculation.

As a result of the unsuccessful test of the Northwest Lost Hills # 1-22 well in January 2006, we fully evaluated the Northwest Lost Hills prospect as at December 31, 2005 resulting in an addition of $8.9 million to the carrying value of our U.S. cost center for the ceiling test calculation. However, no impairment of our U.S. oil and gas properties was required in 2005 for Canadian GAAP purposes.

Impairment of Oil and Gas Properties 2004 vs. 2003

We impaired our U.S. oil and gas properties by $16.3 million in 2004, compared to an impairment of $20.0 million in 2003. The impairment for 2004 is due to an evaluation of a number of our proved properties at the Knights Landing, Citrus and South Midway fields, and a further impairment of our unproved properties, primarily Northwest Lost Hills. At the Knights Landing gas field, our 2004 drilling resulted in three successful completions and six dry holes. We plan to use 3-D seismic to improve the discovery rate in this field when we resume drilling in 2006. The impairment of our Northwest Lost Hills prospect reflected the farm-out of a portion of our working interest to fund a test of the well, which was completed unsuccessfully in 2006.

No impairment of our China oil and gas properties was required in 2004 for Canadian GAAP purposes.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents decreased by $2.6 million for the year ended December 31, 2005 compared to a decrease of $5.2 million and an increase of $10.5 million for the same periods in 2004 and 2003, respectively.

Operating Activities

Our operating activities provided $9.4 million in cash for the year ended December 31, 2005 compared to $4.0 million provided by operating activities for the same period in 2004 and $1.5 million used by operating activities for the same period in 2003. The increases in cash from operating activities for the years ended December 31, 2005 and 2004 were mainly due to increases in net production volumes of 26% and 41%, respectively, and increases in oil and gas prices of 33% and 32%, respectively. The increases in net revenues for the years ended December 31, 2005 and 2004 were partially offset by increases of $4.5 million and $0.2 million, respectively, in general and administrative and business and product development expenses, excluding stock based compensation, and a $0.8 million increase in interest expense and financing costs for the year ended December 31, 2005 when compared to the same period in 2004.

Investing Activities

Our investing activities used $51.1 million in cash for the year ended December 31, 2005 compared to $34.7 million used in investing activities for the same period in 2004. For the year ended December 31, 2005, compared to the same period in 2004, we spent $13.5 million more on the Merger, which was completed in April 2005, and we advanced $1.2 million during 2005 under a consultancy agreement. In addition, we had no sales of assets for the year ended December 31, 2005 compared to $14.0 million of cash generated from asset sales in China for the comparable period in 2004. These increases in our investing activities for the year ended December 31, 2005 were partially offset by an $11.9 million decrease in cash required for our capital investment activities for 2005 when compared to the same period in 2004, which was mainly due to an $8.8 million increase in our non-cash working capital associated with our investing activities.

For the year ended December 31, 2004, we used $27.3 million more in cash for capital investment activities and $4.5 million more on Merger related activities than for the comparable period in 2003. This was partially offset by $14.0 million of cash generated from asset sales in China for the year ended December 31, 2004 when compared to the same period in 2003.

Financing Activities

Our financing activities provided $39.2 million in cash for the year ended December 31, 2005 compared to $25.4 million of cash provided by financing activities for the comparable period in 2004. We closed three special warrant financings by way of private placements during the year ended December 31, 2005 and issued 13.8 million common shares for net proceeds of $26.7 million compared to two special warrant financings by way of private placements for the year ended December 31, 2004 and issued 7.2 million common shares for $20.4 million. A special warrant is a security sold for cash which may be exercised to acquire, for no additional consideration, a common share or, in certain circumstances, a common share and a common share purchase warrant See Item 5 of this Annual Report on Form 10-K, Sales of Unregistered Securities . We generated $4.5 million more from the exercise of stock options and common share purchase warrants for the year ended December 31, 2005 compared to the same period in 2004.

We generated $6.3 million in cash from net debt financing for the year ended December 31, 2005 compared to $3.3 million in cash for the same period in 2004. For the year ended December 31, 2005, we received $8.0 million from two convertible loans, $4.0 million of which was refinanced in November 2005 by the issuance of 2.5 million common shares. For the year ended December 31, 2004, we received $4.0 million from our bank loan facility to develop the southern expansion of South Midway. For the years ended December 31, 2005 and 2004 we made principal payments on our bank loan of $1.7 million and $0.7 million, respectively.

For the year ended December 31, 2004, we generated $3.0 million less in cash from financing activities than for the comparable period in 2003. We closed three special warrant financings by way of private placements during the year ended December 31, 2003 and issued 12.7 million common shares for net proceeds of $24.1 million compared to two special warrant financings by way of private placements for the year ended December 31, 2004 and issued 7.2 million common shares for $20.4 million. We generated $2.2 million more from the exercise of stock options and common share purchase warrants for the year ended December 31, 2003 compared to the same period in 2004. This is partially offset by $3.3 million in net proceeds received from our bank loan facility to develop the southern expansion of South Midway for the year ended December 31, 2004 compared to the same period in 2003.

	Year ended December 31,		
	2005	**2004**	**2003**
Cash flow (deficit) from operating activities	$ 9,358	$ 4,032	$ (1,522)
Investing Activities			
Capital investments, after changes in non-cash working capital	(31,279)	(43,190)	(15,928)
Merger, net of working capital	(10,096)		
Equity investment and Merger related costs	(8,462)	(5,016)	(500)
Proceeds from sale of assets		13,958	
Advance payments	(1,200)		
Other	(78)	(410)	(37)
	(51,115)	(34,658)	(16,465)
Financing Activities			

Proceeds from private placements, net of all share issue costs	26,578	20,428	24,070
Proceeds from exercise of options and purchase warrants	6,248	1,723	3,928
Net debt financing	6,333	3,306	500
	39,159	25,457	28,498
Net Sources (Uses) of Cash	$ (2,598)	$ (5,169)	$ 10,511

<u>Outlook for 2006</u>

Our capital investment budget for 2006 is $37.4 million. Approximately 60% of our 2006 capital investment budget is for oil and gas exploration and development activities, primarily in the U.S, where we plan to drill 23 development wells and 15 exploration wells. In China, we plan to drill three development wells at the Dagang field and one exploration well in the Zitong block during 2006. The remaining 40% of our capital investment budget is split evenly between GTL and EOR, including heavy oil processing activities. If we are successful in negotiating a definitive agreement for a GTL plant in Egypt as well as for one or more RTP™ Plants in North America, we will commence with front-end engineering and design activities in 2006.

We incurred a net loss of $13.5 million for the year ended December 31, 2005, and, as at December 31, 2005, had an accumulated deficit of $95.3 million and negative working capital of $11.4 million. We plan to finance approximately 50% of our 2006 capital investment budget with cash generated from operations but this will not be sufficient to satisfy our current obligations and meet our capital investment objectives. Our plans include the sale of additional equity securities, alliances or other partnership agreements with entities with the resources to support our projects as well as convertible loan, debt and mezzanine financing in order to generate sufficient resources to assure continuation of our operations and achieve our capital investment objectives. We continue active negotiation with a third party for the formation of a joint venture for the deployment, in a specific region of the world, of the GTL and RTP technologies we license or own. The transaction that is being discussed would, if consummated, include a potentially significant equity investment in Ivanhoe by the third party. No assurances can be given that we and the third party with whom we are presently negotiating will successfully conclude this potential transaction nor that we will be able to raise additional capital or enter into one or more alternative business alliances with other parties if this potential transaction is not successfully concluded. If we are unable to obtain adequate additional financing or enter into such business alliances, we will be required to sharply 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 (stated in thousands of U.S. dollars)				
	Total	**2006**	**2007**	**2008**	**2009**	**After 2009**
Purchase Agreement:	$ 100	$ 100	$	$	$	$
Consolidated Balance Sheet:						
Note payable current portion *(Note 7)*	1,667	1,667				
Long term debt *(Note 7)*	4,972		4,972			
Asset retirement obligations *(Note 8)*	1,780	950	100			730
Long term obligation *(Note 9)*	1,900		1,900			
CITIC note payable *(Note 22)*	7,386	2,050	2,460	2,460	416	
Other Commitments:						
Interest payable (1)	762	458	304			
Lease commitments *(Note 9)*	2,287	763	608	461	287	168
Zitong exploration commitment *(Note 9)*	4,300	4,300				
Total	$ 25,154	$ 10,288	$ 10,344	$ 2,921	$ 703	$ 898

(1) This is the estimated future interest payments on our notes payable and long term debt using the rates of interest in effect as at

December 31,
2005.

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 in Item 8 of this Annual Report on Form 10-K. 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 23 to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K. 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 23 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, 2005, the carrying values of our U.S. and China cost centers were $43.1 million and $56.0 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. The reserve numbers and values included in this Annual Report on Form 10-K 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. See Risk Factors .

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 2005, oil and gas depletion of $14.3 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2005 would have changed by approximately $1.5 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 in this Annual Report on Form 10-K 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 in this Annual Report on Form 10-K.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in this Annual Report on Form 10-K 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.

(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.

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, 2005, we had $9.7 million and $5.3 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 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, effective January 2004, 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. 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 $16.3 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2004 and 2003, respectively, and $5.0 million for the year ended December 31, 2005 for our China cost center.

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 [1] of a cost center s oil and gas properties cannot exceed the discounted future net cash flows 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 income tax effects related to differences between the book and tax basis of the properties. The net cash flows of a cost center s proved reserves are discounted by ten percent. 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 $2.8 million, $15.0 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2005, 2004 and 2003, respectively, and $1.7 million for the year ended December 31, 2005 for our China cost center.

(1) 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 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.

Asset Retirement For Canadian GAAP, we follow Canadian Institute of Chartered Accountants (**CICA**) Section 3110, Asset Retirement Obligations which requires, for fiscal years beginning after January 1, 2004, 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.

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 GTL and EOR projects, including RTP™ 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 product 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 GTL and EOR assets. For the years ended December 31, 2005, 2004 and 2003, we wrote down $0.6 million, $0.3 million and $3.3 million, respectively, of capitalized negotiation and feasibility costs associated with our GTL and EOR projects which did not result in definitive agreements.

Additionally, we incur costs to develop, enhance and identify improvements in the application of the GTL and RTP™ 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 GTL and EOR assets. Costs incurred in the operation of equipment and facilities used to develop or enhance GTL and RTP™ technologies prior to commencing commercial operations are business and product 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 product 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 GTL or EOR definitive agreement are considered to be research and development costs and are expensed as incurred. For the years ended December 31, 2005, 2004 and 2003, we expensed $5.5 million, $2.1 million and $0.8 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 a master license from Syntroleum permitting us to use the Syntroleum Process in an unlimited number of projects around the world and an exclusive, irrevocable license we acquired in the Merger with Ensyn to deploy, worldwide, the RTP™ Technology for petroleum applications as well as the exclusive right to deploy RTP™ Technology in all applications other than biomass. 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 Syntroleum GTL master license and RTP™ Technology have finite lives, which correlate with the useful lives of the GTL or RTP™ facilities we expect to develop that will use the Syntroleum Process and

RTP™ Technology. The amount of the carrying value of the technologies we assign to each GTL or RTP™ facility will be amortized to earnings on a basis related to the operations of the GTL or RTP™ facility from the date on which the facility is placed into service. We evaluate the carrying values of the Syntroleum GTL master license and RTP Technology 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.

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. We apply SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on our financial statements.

In January 2005, the CICA approved Section 3251 Equity which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on our financial statements.

The following standards issued by the CICA do not impact us at this time:

Section 3831, Non-Monetary Transactions , effective for non-monetary transactions initiated in periods beginning on or after January 1, 2006.

Emerging Issues Committee of the CICA issued Abstract No. 157, Implicit Variable Interests Under AcG-15 , effective in the first quarter of 2006.

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

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation (**SFAS No. 123(R)**), which supersedes APB No. 25, Accounting for Stock Issued to Employees . SFAS No. 123(R) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. We apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and do not recognize compensation costs in our financial statements for stock options issued to our employees and directors. SFAS No. 123(R) is effective for the first annual reporting period that begins after June 15, 2005 and may be implemented on a modified prospective or retrospective basis. We have elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis we would recognize stock based compensation in our U.S. GAAP results of operations for the unvested portion of awards outstanding as of January 1, 2006 and for all awards granted after January 1, 2006. We expense stock based compensation in our financial statements for Canadian GAAP and expect that the impact of implementing SFAS No. 123(R) will not be materially different for U.S. GAAP purposes.

To assist in the implementation of SFAS No. 123(R), the SEC issued SAB No. 107, Share-Based Payment (**SAB No. 107**). While SAB No. 107 addresses a wide range of issues, the largest area of focus is valuation methodologies and the selection of assumptions. Notably, SAB No. 107 lays out simplified methods for developing certain assumptions. In addition to providing the SEC staff s interpretive guidance on SFAS No. 123(R), SAB No. 107 addresses the interaction of SFAS No. 123(R) with existing SEC guidance (e.g., the interaction with the SEC s guidance dealing with non-GAAP disclosures). Its intent is to clarify, not change, any of SFAS No. 123(R) s guidance.

In May 2005, the FASB issued SFAS No. 154 (**SFAS No. 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 applies to all voluntary changes in accounting principle. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 carries forward without change to the guidance contained in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 also carries forward the guidance in APB Opinion No. 20 requiring justification of a change in accounting principle on the basis of preferability. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

On July 14, 2005, the FASB published an exposure draft entitled Accounting for Uncertain Tax Positions - an interpretation of SFAS No. 109. The proposed interpretation is intended to reduce the significant diversity in practice associated with recognition and measurement of income taxes by establishing consistent criteria for evaluating uncertain tax positions. The proposed interpretation would be effective for the first fiscal year beginning after December 15, 2006. Earlier application would be encouraged. Only tax positions meeting the probable recognition threshold at that date would be recognized. The transition adjustment resulting from application of this interpretation would be recorded as a cumulative-effect change in the income statement as of the end of the period of adoption. Restatement of prior periods or pro forma disclosures under APB Opinion No. 20, Accounting Changes , would not be permitted. The implementation of this exposure draft is not expected to impact us at this time.

On September 30, 2005, the FASB issued an Exposure Draft that would amend SFAS No. 128, Earnings per Share , to clarify guidance for mandatorily convertible instruments, the treasury stock method, contracts that may be settled in cash or shares and contingently issuable shares. The proposed Statement would be effective for interim and annual periods ending after June 15, 2006. Retrospective application would be required for all changes to SFAS No. 128, except that retrospective application would be prohibited for contracts that were either settled in cash to prior adoption to require cash settlement. We are in the process of reviewing the requirements of this recent exposure draft.

The following standards issued by the FASB do not impact us at this time:

SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 , effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

FASB issued Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 , effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises).

Off Balance Sheet Arrangements

At December 31, 2005 and 2004, 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 $3.0 million, $1.6 million and $1.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. As at December 31, 2005 and 2004, amounts included in accounts payable under these arrangements were $0.3 million and $0.1 million, respectively.

In 2003, we borrowed $1.25 million from a related company controlled by one of our directors. The loan, plus accrued interest, was repaid in September 2003.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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. We estimate that we will need approximately $20.0 to $25.0 million from the equity markets to fund our capital investment programs for 2006.

We can give no assurance that we will be successful in obtaining financing from equity markets as and when needed. Factors beyond our control may make it difficult or impossible for us to obtain equity financing on favorable terms or at all. Failure to obtain any required equity 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. We estimate that our net income and cash from operations for 2006 would change $0.9 million and $0.3 million for every $1.00/Bbl change in WTI prices and $0.50/Mcf in natural gas prices, respectively.

We periodically engage in the use of derivatives to hedge our cash flow from operations but have no hedge contracts in place as at December 31, 2005. See Note 14 to the Consolidated Financial Statements in Item 8.

Decreases in oil and natural gas prices would negatively impact our results of operations as a direct result of a reduction in revenues but may also do so in the ceiling test calculation for the impairment of our oil and gas properties. On a quarterly basis, we compare the value of our proved and probable reserves, using estimated future oil and gas prices [(1)], to the carrying value of our oil and gas properties. The ceiling test calculation is sensitive to oil and gas prices and in a period of declining prices could result in a charge to our results of operations as we experienced in 2001 when we recorded a $14.0 million provision for impairment for Canadian GAAP and an additional $10.0 million for U.S. GAAP mainly due to a decline in oil and gas prices. Decreases in oil and gas prices from those used in our ceiling test calculation as at December 31, 2005 as discussed above in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties may result in additional impairment provisions of our oil and gas properties.

(1) The recoverable value of probable reserves is included only for the measurement of the impairment of the carrying value of oil and gas properties as required under Canadian GAAP but not for U.S. GAAP. Additionally, U.S. GAAP requires the use of period end oil and gas prices to measure the amount of the impairment rather than estimated future oil and gas prices as required by Canadian

GAAP. See Critical Accounting Principles and Estimates in Item 7 in this Annual Report on Form 10-K for the difference between Canadian and U.S. GAAP in calculating the impairment provision for oil and gas properties.

Foreign Currency Rate Risk

In the international petroleum industry, most production is bought and sold in U.S. dollars or with reference to the U.S. dollar. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues. Most of our business transactions, in the countries in which we operate, are conducted in U.S. dollars or currencies, such as Chinese renminbi, which was pegged to the U.S. dollar. During the third quarter of 2005, the Chinese central government increased the value of its renminbi and abandoned its exchange rate previously pegged to the U.S. dollar in favor of a link to a basket of world currencies. We incurred insignificant foreign currency exchange gains or losses during the three years ended December 31, 2005. We do not expect fluctuations in any of the currencies in which we transact business to have a material impact on our consolidated financial statements.

Interest Rate Risk

We currently have minimal debt obligations with fluctuating interest rates and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Information

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

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

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2005 and 2004 and the consolidated statements of loss and shareholders equity and cash flow for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as at December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2006 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 24, 2006

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS FOR U.S. READERS ON CANADA U.S. REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when the financial statements are affected by conditions and events that cast substantial doubt on the Company s ability to continue as a going concern, such as those described in Note 2 to the financial statements. The standards of the Public Company Accounting Oversight Board (United States) also require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company s financial statements and changes in accounting principles that have been implemented in the financial statements. As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations (Canadian Institute of Chartered Accountants (CICA) Handbook Section 3110), stock-based compensation (CICA Handbook Section 3870), hedge accounting (CICA Accounting Guideline 13) and full cost method of accounting (CICA Accounting Guideline 16). Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors and Shareholders dated February 24, 2006 is expressed in accordance with Canadian reporting standards which do not permit a reference to such conditions and events and changes in accounting principles in the auditors report when these are adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 24, 2006

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IVANHOE ENERGY INC.
Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	As at December 31,	
	2005	**2004**
Assets		
Current Assets		
Cash and cash equivalents	$ 6,724	$ 9,322
Accounts receivable (net of allowance for doubtful accounts of $83 and nil as at December 31, 2005 and 2004, respectively) *(Note 3)*	9,994	5,377
Prepaid and other current assets	338	812
	17,056	15,511
Oil and gas properties and investments, net *(Note 4)*	119,654	86,551
Intangible assets technology *(Note 5)*	102,068	10,000
Long term assets *(Note 6)*	2,099	6,424
	$ 240,877	$ 118,486
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 25,791	$ 9,845
Note payable current portion *(Note 7)*	1,667	1,667
Asset retirement obligations current portion *(Note 8)*	950	
	28,408	11,512
Long term debt *(Note 7)*	4,972	2,639
Asset retirement obligations *(Note 8)*	830	749
Long term obligation *(Note 9)*	1,900	
Commitments and contingencies *(Note 9)*		
Shareholders Equity		
Share capital, issued and outstanding 220,779,335 common shares; December 31, 2004 169,664,911 common shares *(Note 10)*	291,088	183,617
Purchase warrants	5,150	
Contributed surplus	3,820	1,748
Accumulated deficit	(95,291)	(81,779)
	204,767	103,586
	$ 240,877	$ 118,486

(See accompanying Notes to Consolidated Financial Statements)

Approved by the Board:

(signed) David R. Martin	(signed) E. Leon Daniel
Director	Director

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IVANHOE ENERGY INC.
Consolidated Statements of Loss
(stated in thousands of U.S. Dollars, except share amounts)

	Year ended December 31,		
	2005	**2004**	**2003**
Revenue			
Oil and gas revenue	$ 29,800	$ 17,795	$ 9,569
Interest income	139	202	90
	29,939	17,997	9,659
Expenses			
Operating costs	7,603	5,073	4,293
General and administrative	9,529	7,275	6,880
Business and product development	4,978	1,913	1,331
Depletion and depreciation	14,447	7,482	3,829
Interest expense and financing costs	1,258	379	184
Write-downs and provision for impairment *(Notes 4 and 15)*	5,636	16,600	23,321
	43,451	38,722	39,838
Net Loss	$ 13,512	$ 20,725	$ 30,179
Net Loss per share Basic and Diluted ***(Note 17)***	$ 0.07	$ 0.12	$ 0.20
Weighted Average Number of Shares (in thousands)	195,803	167,612	150,154

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.
Consolidated Statements of Shareholders Equity
(stated in thousands of U.S. Dollars, except share amounts)

	Share Capital Shares (thousands)	Share Capital Amount	Purchase Warrants	Contributed Surplus	Accumulated Deficit	Total
Balance December 31, 2002	144,466	$ 131,112	$	$ 311	$ (30,875)	$ 100,548
Net loss					(30,179)	(30,179)
Shares issued for:						
Private placements, net of share issue costs	12,654	24,070				24,070
Conversion of debt	2,000	1,000				1,000
Exercise of purchase warrants *(Note 10)*	250	425				425
Exercise of options	1,363	3,773		(271)		3,502
Services	626	695				695
Stock based compensation				476		476
Balance December 31, 2003	161,359	161,075		516	(61,054)	100,537
Net loss					(20,725)	(20,725)
Shares issued for:						
Private placements, net of share issue costs	7,173	20,428				20,428
Exercise of options	975	1,767		(44)		1,723
Services	158	347				347
Stock based compensation				1,276		1,276
Balance December 31, 2004	169,665	183,617		1,748	(81,779)	103,586
Net loss					(13,512)	(13,512)
Shares and purchase warrants issued for:						
Merger, net of share issue costs *(Note 20)*	30,000	74,907				74,907
Private placements, net of share issue costs	13,842	21,834	4,837			26,671
Refinance of convertible debt *(Note 7)*	2,454	4,000	313			4,313
Exercise of purchase warrants *(Note 10)*	4,515	6,133				6,133
Exercise of options	111	156		(41)		115
Services	192	441				441
Stock based compensation				2,113		2,113

Balance December 31, 2005	220,779	$ 291,088	$ 5,150	$ 3,820	$ (95,291)	$ 204,767

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.
Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2005	**2004**	**2003**
Operating Activities			
Net loss	$ (13,512)	$ (20,725)	$ (30,179)
Items not requiring use of cash:			
Depletion and depreciation	14,447	7,482	3,829
Write-downs and provision for impairment *(Notes 4 and 15)*	5,636	16,600	23,321
Stock based compensation *(Note 2 and 11)*	2,113	1,276	476
Write off of debt financing costs *(Note 6)*	345		
Other	108	47	
Changes in non-cash working capital items	221	(648)	1,031
	9,358	4,032	(1,522)
Investing Activities			
Capital investments	(43,301)	(46,454)	(15,391)
Merger, net of working capital	(10,096)		
Equity investment and Merger related costs *(Notes 6 and 20)*	(1,712)	(5,016)	(500)
Acquisition of joint venture interest *(Notes 10 and 21)*	(6,750)		
Proceeds from sale of assets *(Note 4)*		13,958	
Advance payments *(Note 6)*	(1,200)		
Other	(78)	(410)	(37)
Changes in non-cash working capital items	12,022	3,264	(537)
	(51,115)	(34,658)	(16,465)
Financing Activities			
Proceeds from private placements, net of share issue costs	26,671	20,428	24,070
Proceeds from exercise of options and purchase warrants	6,248	1,723	3,928
Share issue costs on shares issued for Merger	(93)		
Proceeds from debt obligations *(Note 7)*	8,000	14,000	1,750
Payments of debt obligations	(1,667)	(10,694)	(1,250)
	39,159	25,457	28,498
Increase (decrease) in cash and cash equivalents, for the year	(2,598)	(5,169)	10,511
Cash and cash equivalents, beginning of year	9,322	14,491	3,980
Cash and cash equivalents, end of year	$ 6,724	$ 9,322	$ 14,491

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(all tabular amounts are expressed in thousands of U.S. Dollars, except share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) enhanced oil recovery (**EOR**) development projects including the application of heavy oil upgrading rapid thermal processing (**RTP**[TM]), 2) the monetization of stranded gas reserves through a licensed gas-to-liquids (**GTL**) technology and 3) conventional exploration and production of oil and gas. Conventional oil and gas operations are currently carried out in the U.S. and China and GTL and EOR projects for a number of countries are in various stages.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles (**GAAP**) in Canada. The impact of material differences between Canadian and U.S. GAAP on the consolidated financial statements is disclosed in Note 23.

The Company s financial statements as at and for the year ended December 31, 2005 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. The Company incurred a net loss of $13.5 million for the year ended December 31, 2005, and, as at December 31, 2005, had an accumulated deficit of $95.3 million and negative working capital of $11.4 million. The Company expects to incur substantial expenditures to further its capital investment programs and the Company s cash flow from operating activities will not be sufficient to satisfy its current obligations and meet its capital investment objectives. Management s plans include the sale of additional equity securities, alliances or other partnership agreements with entities with the resources to support the Company s projects as well as convertible loan, debt and mezzanine financing in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives. The Company is continuing active negotiation with a third party for the formation of a joint venture for the deployment, in a specific region of the world, of the GTL and RTP technologies it licenses or owns. The transaction that is being discussed would, if consummated, include a potentially significant equity investment in the Company by the third party. No assurances can be given that the Company and the third party with whom it is presently negotiating will successfully conclude this potential transaction nor that the Company will be able to raise additional capital or enter into one or more alternative business alliances with other parties if this potential transaction is not successfully concluded. If the Company is unable to obtain adequate additional financing or enter into such business alliances, management will be required to sharply curtail the Company s operations, which may include the sale of assets. The outcome of these matters cannot be predicted with certainty at this time and therefore the Company may not be able to continue as a going concern. These consolidated financial do not include any adjustments to the amounts and classification of assets and liabilities that may be necessary should the Company be unable to continue as a going concern.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Changes in Accounting Policies

<u>Asset Retirement Costs</u>

Prior to January 2003, the Company had estimated its future site restoration and abandonment costs associated with its oil and gas properties and amortized this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision was included with depletion and depreciation expense.

The Canadian Institute of Chartered Accountants (**CICA**) approved Section 3110, Asset Retirement Obligations which requires, for fiscal years beginning after January 1, 2004, 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.

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The Company elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company s financial position and results of operations in prior years (See Notes 4 and 8).

Stock Based Compensation

Prior to January 1, 2004, the Company accounted for stock options granted to employees and directors using the intrinsic-value of the stock options. Under this method, compensation costs were not recognized in the financial statements for stock options granted at market value but rather disclosure was required, on a pro forma basis, of the impact on net income of using the fair value at the stock option grant date. The Company recognizes compensation costs in its financial statements for stock options granted to non-employees after January 1, 2002 based on the fair value of the stock options at the date granted.

The CICA approved Section 3870, Stock Based Compensation and Other Stock Based Payments which requires, for fiscal years beginning on or after January 1, 2004, compensation costs to be recognized in the financial statements using the fair value based method of accounting for all stock options granted after January 1, 2002. Implementation of this change in accounting policy requires retroactive application with the option of restating financial statements of prior periods.

Accordingly, effective January 1, 2004, the Company changed its accounting policy, for Canadian GAAP purposes, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. This change was adopted retroactively and the Company restated its financial statements of prior periods. The Company uses the Black-Scholes option-pricing model for determining the fair value of all stock options issued at grant date.

Principles of Consolidation

As more fully described in Note 20, on April 15, 2005 the Company acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) pursuant to a merger between Ensyn and a wholly owned subsidiary of the Company (**Merger**) in accordance with an Agreement and Plan of Merger dated December 11, 2004 (**Merger Agreement**). This acquisition was accounted for using the purchase method. As part of the Merger, the Company acquired a 50% interest in a joint venture, which owns the RTP™ commercial demonstration facility (**RTP™ CDF**) located in California s San Joaquin Basin, as well as certain rights to manufacture RTP™ facilities. In November 2005, the Company acquired the remaining 50% in the joint venture, which effectively dissolved the joint venture (see Note 21). These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, including those acquired in the Merger, all of which are wholly owned.

The Company conducts most exploration, development and production activities in its oil and gas business jointly with others. The Company s accounts reflect only its proportionate interest in the assets and liabilities of these joint ventures.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company uses the U.S. Dollar as its functional currency since it is the currency in which the worldwide petroleum business is denominated. Monetary assets and liabilities denominated in foreign currencies are converted to the U.S. Dollar at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted to the U.S. Dollar at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the period-end translation of monetary assets and liabilities denominated in foreign currencies are reflected in the results of operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company s cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, note payable and long-term debt approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

Oil and Gas Properties

Full Cost Accounting

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country (cost center) basis. Such expenditures include lease and royalty interest acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs related to capital projects and asset retirement costs. The Company periodically evaluates its unproved properties for exploration and exploitation opportunities. If the Company determines that the exploration or exploitation potential of an unproved property has diminished, all, or a portion, of the costs incurred on such property is impaired and transferred to the carrying value of proved oil and gas properties. Proceeds from sales of oil and gas properties are recorded as reductions in the carrying value of proved oil and gas properties, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Depletion

The Company s share of costs for proved oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit-of-production method over the life of the Company s share of estimated remaining proved oil and gas reserves. 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. Significant development projects and expenditures on unproved properties are excluded from the depletion calculation until evaluated. Natural gas reserves and production are converted to a barrels of oil equivalent using a generally recognized industry standard in which six thousand cubic feet of gas is equal to one barrel of oil. Barrels of oil equivalent 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.

Impairment of Proved Oil and Gas Properties

Prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center s carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes (**ceiling test**).

Effective January 2004, the Company prospectively adopted Accounting Guideline 16 Oil and Gas Accounting Full Cost which requires recognition and measurement processes to assess impairment of oil and gas properties. In the recognition of an impairment, the carrying value 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. 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.

Asset Retirement Costs

The Company measures the expected costs required to abandon its producing U.S. oil and gas properties and the RTP™ CDF 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. 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.

Asset retirement costs associated with the producing U.S. oil and gas properties are being depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. Asset retirement costs associated with the RTP™ CDF will be depreciated over the life of the RTP™ CDF commencing when the facility is placed into service. The accretion of the liabilities for the asset retirement obligations is included with interest expense.

The Company does not make such a provision for its oil and gas operations in China as there is no obligation on the Company s part to contribute to the future cost to abandon the field and restore the site.

Development Costs

The Company incurs various costs in the pursuit of EOR and GTL projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**), or similar agreements, are considered to be business and product development and are expensed as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses 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 project s capitalized costs, which are deemed to have no future value, are written down to the results of operations with a corresponding reduction in the investments in EOR and GTL assets.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the RTP™ and GTL technologies it licenses or owns. The cost of equipment and facilities acquired, such as the RTP™ CDF, or constructed for such purposes are capitalized development costs 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. The RTP™ CDF will be used to develop and identify improvements in the application of the RTP™ Technology by processing and testing heavy crude feedstock of prospective partners until such time as the RTP™ CDF is sold or dismantled and redeployed.

The Company reviews 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 EOR and GTL assets.

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

Furniture and Equipment

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Intangible Assets

Intangible assets are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their useful lives. 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 Company owns intangible assets in the form of a GTL master license from Syntroleum Corporation (**Syntroleum**) and an exclusive, irrevocable license to employ rapid thermal processing technology (**RTP™ Technology**) for petroleum applications. The Company will assign the carrying value of the Syntroleum GTL master license and the RTP™ Technology to the number of facilities it expects to develop that will use the Syntroleum GTL process and RTP™ Technology, respectively. The amount of the carrying value of the technologies assigned to each GTL or RTP™ facility will be amortized to earnings on a basis related to the operations of the GTL or RTP™ facility from the date on which the facility is placed into service. The carrying value of the Syntroleum GTL master license and RTP Technology are evaluated for impairment annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of their fair market values.

Oil and Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer. Oil and gas revenue represents the Company s share and is recorded net of royalty payments to governments and other mineral interest owners.

In China, the Company conducts operations jointly with the government of China in accordance with a production-sharing contract. Under this contract, the Company pays both its share and the government s share of operating and capital costs. The Company recovers the government s share of these costs from future revenues or production over the life of the production-sharing contract. The government s share of operating costs is recorded in operating expense when incurred and capital costs are recorded in oil and gas properties and expensed to depletion and depreciation in the year recovered. All recoveries of the government s share of costs are recorded as oil and gas revenue in the year of recovery.

Earnings or Loss Per Share

Basic earnings or loss per share is calculated by dividing the net earnings or loss to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflects the potential dilution that would occur if stock options and purchase warrants were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options and purchase warrants would be used to purchase common shares at the average market price for the period (See Note 17). The Company does not report diluted loss per share amounts, as the effect would be antidilutive to the common shareholders.

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company s assets and liabilities.

Stock Based Compensation

The Company has an Employees and Directors Equity Incentive Plan consisting of stock option, bonus and an employee share purchase plan (See Note 11). The Company accounts for equity-based compensation under this plan using the fair value based method of accounting for all stock options granted after January 1, 2002. Compensation costs are recognized in the results of operations over the periods in which the stock options vest for all stock options granted based on the fair value of the stock options at the date granted. The Company uses the Black-Scholes option-pricing model for determining the fair value of stock options issued at grant date. As of the date stock options are granted, the Company estimates a percentage of stock options issued to employees and directors it expects to be forfeited. Compensation costs are not recognized for stock option awards forfeited due to a failure to satisfy the service requirement for vesting. Compensation costs are adjusted for the actual amount of forfeitures in the period in which the stock options expire.

Upon the exercise of stock options, share capital is credited for the fair value of the stock options at the date granted with a charge to contributed surplus. Consideration paid upon the exercise of the stock options is also credited to share capital.

Compensation expenses are recognized when shares are issued from the stock bonus plan. The employee share purchase portion of the plan has not yet been activated.

Derivative Activities

Prior to January 2004, the Company applied hedge accounting to all derivative instruments used to manage price fluctuations in oil and natural gas prices.

Effective January 1, 2004, the Company adopted CICA Accounting Guideline 13, Hedging Relationships . This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and qualifying as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried at fair value in the statement of financial position, and subsequent changes in their fair value are recorded in the results of operations. The adoption of this accounting guideline did not have a material impact on the consolidated financial statements (See Note 14).

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S.

GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on the Company s financial statements.

In January 2005, the CICA approved Section 3251 Equity which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on the Company s financial statements.

The following standards issued by the CICA do not impact the Company at this time:

Section 3861, Financial Instruments Disclosure and Presentation , effective for fiscal years beginning on or after November 1, 2004.

Accounting Guideline 15, Consolidation of Variable Interest Entities , effective for annual and interim periods beginning on or after November 1, 2004.

3. CONCENTRATION OF CREDIT RISKS

The Company sells oil and natural gas products to pipelines, refineries, major oil companies and foreign national petroleum companies. Where possible, credit is extended based on an evaluation of the customer s financial condition and historical payment record.

The following summarizes the accounts receivable balances and revenues from significant customers:

	Accounts Receivable as at December 31,		**Oil and Gas Revenues for the Year Ended December 31,**		
	2005	**2004**	**2005**	**2004**	**2003**
U.S. Customers					
A	$ 738	$ 542	$ 8,812	$ 6,140	$ 4,392
B	327	398	1,002	1,202	
C	110	193	1,166	1,040	986
D	7	229	605	441	
E	80	71	261	300	273
All others	81	20	2,059	188	65
	1,343	1,453	13,905	9,311	5,716
China Customer					
A	3,519	1,982		8,484	4,103
	4,862	3,435	13,905	17,795	9,819
Receivables from partners	4,888	1,652			
Other receivables	244	290			
	$ 9,994	$ 5,377	$ 13,905	$ 17,795	$ 9,819

Oil and gas revenues for the year ended December 31, 2003 in the table above do not include $0.3 million of oil hedge losses from derivative activities.

Accounts receivable as at December 31, 2005 and 2004 in the table above include $4.9 million and $1.7 million, respectively, of costs billed to joint venture partners where the Company is the operator and advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by segment are as follows:

	As at December 31, 2005				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 99,721	$ 71,760	$	$	$ 171,481
Unproved	9,676	5,320			14,996
	109,397	77,080			186,477
Accumulated depletion	(15,920)	(16,036)			(31,956)
Accumulated provision for impairment	(50,350)	(5,000)			(55,350)
	43,127	56,044			99,171
GTL and EOR Investments:					
Commercial demonstration facility				9,599	9,599
Feasibility studies and other deferred costs			4,570	6,142	10,712
			4,570	15,741	20,311
Furniture and equipment	485	95		15	595
Accumulated depreciation	(380)	(37)		(6)	(423)
	105	58		9	172
	$ 43,232	$ 56,102	$ 4,570	$ 15,750	$ 119,654

	As at December 31, 2004				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 81,648	$ 35,771	$	$	$ 117,419
Unproved	20,447	10,581			31,028
	102,095	46,352			148,447
Accumulated depletion	(10,956)	(6,663)			(17,619)
Accumulated provision for impairment	(50,350)				(50,350)
	40,789	39,689			80,478
GTL and EOR Investments:					
Feasibility studies and other deferred costs			3,793	2,091	5,884
Furniture and equipment	417	84		11	512
Accumulated depreciation	(300)	(22)		(1)	(323)
	117	62		10	189

	$ 40,906	$ 39,751	$ 3,793	$ 2,101	$ 86,551

Costs as at December 31, 2005 and 2004 of $15.0 million and $31.0 million, respectively, related to unproved oil and gas properties were excluded from the depletion and ceiling test calculations.

For the years ended December 31, 2005 and 2004, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $4.6 million and $3.8 million, respectively, were capitalized.

United States

The Company s U.S. oil and gas operations are primarily conducted through joint operations with other oil and gas companies in California, Texas and Wyoming.

The provision for impairment calculated for U.S. oil and gas properties was $16.3 million for the year ended December 31, 2004. No provision for impairment of U.S. oil and gas properties was required for the year ended December 31, 2005 (See Note 15).

Included in the carrying value for the Company s California properties are $9.2 million of costs incurred to acquire overriding royalties in various exploration prospects and producing properties.

During 2000 and 2001, the Company acquired mineral rights in several East Texas prospects under a joint venture with a subsidiary of Unocal Corp. (**Unocal**). Unocal, as operator of the joint venture, was to fund, over a five-year period ending in December 2005, the drilling costs for the first several exploration wells to match $10.1 million in leasehold, seismic and processing costs the Company incurred in these East Texas prospects. Through December 2005, Unocal had spent $8.5 million in exploration drilling and elected to pay the Company $1.6 million for the deficiency in their drilling commitment rather than drill additional exploration wells. The

Company credited the $1.6 million payment to the carrying value of its U.S. oil and gas properties as the payment did not significantly alter the depletion rate for the U.S. cost center.

In 2004, the Company sold its working interest in one of its California producing properties for $0.5 million. The sale proceeds were credited to the carrying value of its U.S. oil and gas properties as the sale did not significantly alter the depletion rate for the U.S. cost center.

China

The Company currently holds a production-sharing contract with China National Petroleum Corporation (**CNPC**) to develop existing oil properties in the Dagang region. In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**) a wholly-owned subsidiary of China International Trust and Investment Corporation, to acquire a 40% working interest in the Dagang field for an up-front payment of $20.0 million following receipt of Chinese regulatory approvals in June 2004. The carrying value of the Company s China oil and gas properties was reduced by $13.5 million for the amount of the proceeds associated with the farm-in of Richfirst to the Dagang field as the reduction in the carrying value did not significantly alter the depletion rate of the China cost center. The farm-out agreement provided Richfirst with the right to convert its working interest in the Dagang field for the Company s common shares 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 the Company acquired Richfirst s 40% working interest (See Note 22). Subsequent to the acquisition of Richfirst s 40% working interest, the Company will incur 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery.

The Company held a production-sharing contract to develop existing oil fields in the Daqing region until the sale of its interest in the field in January 2002. The Company retains an overriding royalty on future production.

The Company also holds a 100% working interest in a thirty-year production-sharing contract with CNPC in a contract area, known as the Zitong block located in the northwestern portion of the Sichuan Basin. In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million subject to the approval of CNPC and PetroChina Company Ltd. (**PetroChina**) (See Notes 9 and 22). Under the terms of the production-sharing contract, the Company and Mitsubishi will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue until costs are recovered and approximately 45% thereafter. CNPC has the option, at the end of appraisal activities, to participate with the Company in any proposed field developments, with up to a 51% working interest.

The provision for impairment calculated for China oil and gas properties was $5.0 million for the year ended December 31, 2005 (See Note 15).

Gas-to-Liquids

Since 2000, the Company has undertaken detailed project feasibility studies for the construction, operation and cost of GTL plants in Qatar, Egypt, Oman and Bolivia. In addition, the Company has conducted marketing, commercialization and transportation feasibility studies for both European and the Asia Pacific regions for GTL diesel and specialty fuels. As at December 31, 2005 and 2004, $4.6 million and $3.8 million, respectively, of costs associated with GTL plant feasibility and marketing studies, which were deemed to have future value, remain capitalized. Recovery of the GTL costs capitalized is dependent upon finalizing contracts to access natural gas reserves in the respective countries and the successful completion of GTL processing plants.

For the years ended December 31, 2005, 2004 and 2003, the Company wrote down $0.3 million, $0.3 million and $3.3 million, respectively, of capitalized negotiation and feasibility costs associated with its GTL projects which did not result in definitive agreements. For the year ended December 31, 2005, the Company wrote down its investment in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant. For the year ended December 31, 2004, GTL investments were written down related to a study for a GTL fuels plant in Oman as the opportunity to build a 45,000 bpd GTL fuels plant in Oman failed to materialize due to a lack of sufficient committed gas volumes to support a plant of that size. For the year ended December 31, 2003, the Company wrote-down its investments in connection with negotiation costs incurred to construct and operate a GTL production facility in Qatar, which was terminated in 2003 without reaching a definitive agreement.

Enhanced Oil Recovery and Heavy Oil Processing

Subsequent to executing an MOU, the Company capitalizes costs it incurs to determine the technical and commercial feasibility of an EOR project using the latest enhanced recovery and heavy oil processing techniques and technologies. If no definitive agreement is reached for the commercial development of an EOR or heavy oil processing project, then the project s capitalized costs are written down to the results of operations with a corresponding reduction in the investments in EOR assets.

As at December 31, 2005 and 2004, EOR investments included $2.0 million and $0.2 million, respectively, of costs to further the Company s study of the Qaiyarah heavy oil field in Iraq, $2.9 million and $1.9 million, respectively, on other Iraq projects including four engineering, design and procurement contract bids submitted in 2004 and 2005, which are currently being considered by the Iraqi government, and $1.2 million for a preliminary design package prepared in 2005 for a 15,000 barrels-per-day feed of raw, heavy oil commercial RTP facility.

Recovery of the capitalized EOR investments is dependent upon finalizing definitive agreements for, and successful completion of, the various Iraq EOR projects in process and a commercial RTP™ facility and a stable political and economic climate.

Additionally, as at December 31, 2005, EOR investments included $8.9 million of costs associated with acquiring the RTP™ CDF, as part of the Merger and subsequent purchase of the RTP™ Joint Venture interest (see Note 21), plus $0.6 million in improvements to ready the facility for its intended purpose and $0.1 million of estimated costs to dismantle the RTP™ CDF and restore the site it utilizes. The RTP™ CDF was in a commissioning phase as at December 31, 2005 and, as such, was not depreciated, nor impaired, for the year ended December 31, 2005. The RTP™ CDF was placed into service in the first quarter of 2006.

For the year ended December 31, 2005, the Company wrote down $0.3 million related to its MOU with Ecopetrol S.A. (**Ecopetrol**) for the Llanos Heavy Basin Crude Project , which included the Castilla and Chichimene field developments, as the Company did not meet the company-size requirements specified by Ecopetrol in their final bidding qualifications.

5. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following. These intangible assets were not amortized and their carrying values were not impaired for the years ended December 31, 2005, 2004 and 2003.

RTP™ Technology

In the Merger with Ensyn, the Company acquired an exclusive, irrevocable license to deploy, worldwide, the RTP™ Technology for petroleum applications as well as the exclusive right to deploy RTP™ Technology in all applications other than biomass. The RTP™ Technology upgrades the quality of heavy oil by producing lighter, more valuable crude oil. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and potentially reduces transportation costs to marketing points. The RTP™ Technology uses readily available plant and process components. The Company s carrying value of the RTP™ Technology as at December 31, 2005 and 2004 was $92.1 million and nil, respectively.

Syntroleum GTL Master License

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use Syntroleum s proprietary GTL process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. In July 2003, the master license was amended in respect of GTL projects in which both the Company and Syntroleum participate such that no additional license fees or royalties will be payable by the Company and that Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum GTL master license as at December 31, 2005 and 2004 was $10.0 million.

6. LONG TERM ASSETS

During 2004, prior to entering into the Merger Agreement, the Company acquired from Ensyn a 15% equity interest in Ensyn Petroleum International Ltd. (**EPIL**) and exclusive rights to use the RTP™ Technology for petroleum applications in key international markets. Ensyn, the parent company of EPIL, retained the remaining 85% of EPIL. The $3.0 million cost to acquire the 15% equity interest in EPIL plus $2.5 million of costs incurred by the Company in connection with the Merger, including $1.0 million to acquire an option to purchase an additional 5% of EPIL (which expired, unexercised, in January 2005) were included in long-term assets as at December 31, 2004. The Merger was completed on April 15, 2005 and the 15% equity interest in EPIL was eliminated upon consolidating the accounts of the Company and its subsidiaries as at December 31, 2005. An additional $1.7 million of Merger related costs were incurred in 2005. The $4.2 million of Merger related costs were allocated among the net assets acquired in the Merger (See Note 20).

In 2004, the Company incurred $0.4 million in legal fees and other costs to obtain debt financing for the Company s Dagang field development project in China. As at December 31, 2004, these costs were deferred and included in long-term assets. In the third quarter of 2005, the Company assessed production levels and future drilling activity in this project and suspended its project-financing discussions with potential lending institutions. Accordingly, the Company wrote-off the $0.4 million of deferred financing costs to general and administrative expenses for the year ended December 31, 2005. The Company incurred an additional $0.8 million of such costs during the year ended December 31, 2005, which also have been charged to general and administrative expenses.

In January 2005, the Company entered into an agreement with a consultant to advance $0.1 million per month for a twelve month-period for compensation earned and payable in relation to a consultancy agreement between the Company and the consultant. The advances are secured by a second lien on real estate owned by the consultant and are repayable from compensation earned from the consultancy agreement. The advances will be repaid by the consultant over an equal number of months over which the advances were made to the consultant. As at December 31, 2005, the balance of the advance receivable was $1.2 million**.**

In November 2005, the Company refinanced its convertible debt with the issuance of Company shares and a two-year promissory note. In addition, the Company issued purchase warrants to the lender as part of the refinancing agreement. The Company calculated a value of $0.3 million for the purchase warrants issued to the lender, which was recorded as a deferred financing cost to be amortized over the life of the promissory note (See Note 10).

The Company s long-term assets consisted of the following:

	As at December 31,	
	2005	**2004**
Investment in EPIL	$	$ 3,000
Merger related costs		2,513
Long-term advances	1,200	
Drilling deposits	400	400
Deferred debt financing costs	321	384
Other long term deposits and assets	178	127
	$ 2,099	$ 6,424

7. NOTES AND ADVANCE PAYABLE

The scheduled maturities of the notes and advance payable as at December 31, 2005 were as follows:

	Bank Note	**Promissory Note**	**Total**
2006	$ 1,667	$	$ 1,667
2007	972	4,000	4,972
	2,639	4,000	6,639
Less: current portion	1,667		1,667
	$ 972	$ 4,000	$ 4,972

Bank Note

In February 2003, the Company obtained a bank facility for up to $5.0 million to develop the southern expansion of its South Midway field. The bank facility was fully drawn in July 2004 and repayment of the principal and interest commenced in August 2004 with interest at 0.5% above the bank s prime rate or 3.0% over the London Inter-Bank Offered rate (**LIBOR**), at the option of the Company. The principal and interest are repayable, monthly, over a three-year period ending July 2007. The note is secured by all the Company s rights and interests in the South Midway properties.

The note balance, as at December 31, 2005 and 2004, was $2.6 million and $4.3 million, respectively, with a six-month fixed LIBOR rate of 7.375% effective October 13, 2005.

Promissory Note

As at December 31, 2004, the Company had a stand-by loan facility for $6.0 million. In February 2005, the Company borrowed the full amount of this stand-by loan facility and amended the loan agreement to provide the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term to the Company s common shares at U.S.$2.25 per share. In May 2005, the Company finalized a second convertible loan agreement with the same lender for $2.0 million which provided the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term to the Company s common shares at U.S.$2.15 per share. Both convertible loans, which bore interest at 8.0% per annum, originally due on August 23, 2005, were extended for up to three months and were due upon the earliest of i.) five days following receipt of proceeds from a private placement or public offering of the Company s common shares ii.) thirty days following written demand for repayment from lender or iii.) November 23, 2005. A 3% extension fee of approximately $0.3 million was payable on the unpaid principal and interest at maturity. The fair value of the convertible debt approximated its carrying values and accordingly no value was assigned to the equity component of the convertible debt.

In November 2005, the Company closed a special warrant financing by way of a private placement and used a portion of the proceeds from the financing to pay interest and the extension fee of approximately $0.7 million accrued on the convertible debt. Concurrently with the November 2005 private placement, the Company signed an agreement with the lender of the convertible debt to repay $4.0 million of the convertible debt with 2,453,988 common shares of the Company at U.S.$1.63 per share. Additionally, the residual $4.0 million of convertible debt was refinanced with a $4.0 million promissory note due November 23, 2007 with interest payable monthly at a rate of 8% per annum. The previously granted conversion rights attached to the convertible debt were cancelled and the Company granted the lender 2,000,000 purchase warrants, each of which entitles the holder to purchase one common share at a price of U.S. $2.00 per share until November 2007 (See Note 10).

Advance Payable

In March 2004, the Company received a $10.0 million advance as part of the $20.0 million up-front payment due from Richfirst for their farm-in to the Dagang field (See Note 4). Upon finalization of the farm-in agreement in June 2004, Richfirst elected to apply $10.0 million of the up-front payment due to the Company against the advance.

Revolving Line of Credit

The Company has a revolving credit facility for up to $1.25 million from a related party, repayable with interest at U.S. prime plus 3%. The Company did not draw down any funds from this credit facility for the years ended December 31, 2005 and 2004.

8. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties and the RTP™ CDF. The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at December 31, 2005 was estimated at $2.3 million. The liability for the expected future cash flows, as reflected in the financial statements, has been discounted at 5% to 7% and the changes in the Company s liability for the two-year period ended December 31, 2005 were as follows:

Balance as at December 31, 2003	$ 521
Liabilities incurred	180
Accretion expense	48
Balance as at December 31, 2004	749
Liabilities incurred	1,052
Liabilities settled	(2)
Accretion expense	76
Revisions in estimated cash flows	(95)
Balance as at December 31, 2005	1,780
Less: current portion	950
	$ 830

The current portion of the asset retirement obligation at December 31, 2005 was the Company s provision for the cost to abandon the Northwest Lost Hills # 1-22 well in 2006.

9. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

With the signing of the production-sharing contract for the Zitong block, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase 1**). The Phase 1 work program included acquiring approximately 300 miles of new seismic lines, reprocessing approximately 1,250 miles of existing seismic and drilling a minimum of approximately 23,000 feet. The Company completed Phase 1 with the exception of drilling approximately 13,800 feet. The first Phase 1 exploration well drilled in 2005 was suspended, having found no commercial quantities of hydrocarbons. In December 2005, the Company was granted an extension of Phase 1 to May 31, 2006 provided the second Phase 1 exploration well is spud before May 1, 2006. If the second Phase 1 exploration well is spud before May 1, 2006 but the Company is unable to complete the drilling operation before May 31, 2006, CNPC will grant the Company a further six-month extension to complete the drilling operation. In January 2006, the Company farmed out a 10% working interest in the Zitong block to Mitsubishi, as discussed in Note 22. The Company, with

Mitsubishi, is planning to spud a second Phase 1 exploration well in the second quarter of 2006 after which a decision will be made whether or not to enter into the next three-year exploration phase (**Phase 2**). If the Company elects not to enter into Phase 2, it will be required to pay CNPC, within 30 days after its election, a cash equivalent of its share of the deficiency in the work program estimated to be $0.3 million after the drilling of the second Phase 1 well. If the Company elects not to enter Phase 2, the costs related to the Zitong block in the approximate amount of $5.3 million, which are not already included in the depletable base of the China full cost pool, will be subject to the ceiling test. This could result in a ceiling test impairment related to the China full cost pool in an amount, which is not determinable at this time.

Long Term Obligation

As part of the Merger, the Company assumed an obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the RTP™ Technology for petroleum applications reach a total of $100 million. This obligation was recorded in the Company s consolidated balance sheet as at December 31, 2005 as part of the net assets acquired in the Merger.

Other Commitments

The Company assumed an obligation to advance to a subsidiary of Ensyn Corporation, formed from the spin-off of Ensyn s Renewables Business immediately prior to the Merger, up to approximately $0.4 million if this subsidiary cannot meet certain debt servicing ratios required under a Canadian municipal government loan agreement. The loan principal is repayable in nine equal annual installments commencing April 1, 2006 and ending April 1, 2014. Ensyn Corporation has agreed to indemnify the Company for any amounts advanced to the subsidiary under the loan agreement.

The Company may provide indemnifications, in the course of normal operations, that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company s management is of the opinion that any resulting settlements relating to potential litigation matters or indemnifications would not materially affect the financial position of the Company.

Lease Commitments

For the year ended December 31, 2005, the Company expended $0.6 million and $0.5 million for each of the years ended December 31, 2004 and 2003 on operating leases relating to the rental of office space, which expire between March 2007 and July 2010. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses.

As at December 31, 2005, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2006	$ 763
2007	608
2008	461
2009	287
2010	168
Thereafter	
	$ 2,287

10. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Private Placements

From 2003 to 2005, the Company closed nine special warrant financings by way of private placement for net cash proceeds of $26.7 million in 2005, $20.4 million in 2004 and $24.1 million in 2003. A special warrant is a security sold for cash which may be exercised to acquire, for no additional consideration, a common share or, in certain circumstances, a common share and a common share purchase warrant. As part of these special warrant financings, the Company issued 33,669,168 common shares for cash, 2,453,988 common shares for the repayment of $4.0 million of convertible debt (See Note 7) and 34,248,156 purchase warrants. Each purchase warrant entitles the holder to purchase additional common shares of the Company at various exercise prices per share.

Purchase Warrants

The following reflects the changes in the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the three-year period ended December 31, 2005

	Purchase Warrants (thousands)	Common Shares Issuable
Balance December 31, 2002		
Purchase warrants issued for:		
Private placements	10,779	6,015
Balance December 31, 2003	10,779	6,015
Purchase warrants issued for:		
Private placements	7,173	3,587
Purchase warrants exercised	(500)	(250)
Balance December 31, 2004	17,452	9,352
Purchase warrants issued for:		
Private placements	16,296	16,296
Refinance of convertible debt	2,000	2,000
Purchase warrants exercised	(9,029)	(4,515)
Purchase warrants expired	(1,250)	(1,250)
Balance December 31, 2005	25,469	21,883

For the year ended December 31, 2005, 9,029,412 purchase warrants were exercised for the purchase of 4,514,706 common shares at an average exercise price of U.S. $1.36 for a total of $6.1 million. For the year ended December 31, 2004, 500,000 purchase warrants were exercised for the purchase of 250,000 common shares at an exercise price of U.S. $1.70 per share for $0.4 million.

As at December 31, 2005, the following purchase warrants were exercisable to purchase common shares of the Company until the expiry date at the price per share as indicated below:

		Purchase Warrants					
Year of Issue	Price per Special Warrant	Issued	Exercisable (thousands)	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share
2004	U.S. $2.90	5,449	5,449	2,725	$	February 2006	U.S. $3.20
2004	U.S. $2.90	1,724	1,724	862		March 2006	U.S. $3.20
2005	Cdn. $3.10	4,100	4,100	4,100	2,412	April 2007	Cdn. $3.50
2005	Cdn. $3.10	1,000	1,000	1,000	534	July 2007	Cdn. $3.50
2005	U.S. $1.63	11,196	11,196	11,196	1,891	November 2007	U.S. $2.50
2005	n/a	2,000	2,000	2,000	313	November 2007	U.S. $2.00
		25,469	25,469	21,883	$ 5,150		

The weighted average exercise price of the exercisable purchase warrants as at December 31, 2005 was U.S. $2.69 per share.

The previously granted conversion rights attached to the convertible loans were cancelled in November 2005 and the Company granted the lender 2,000,000 purchase warrants, each of which entitles the holder to purchase one common share at a price of U.S. $2.00 per share until November 2007 (See Note 7).

The Company calculated a value of $5.2 million for the purchase warrants issued in 2005. This value was calculated in accordance with the Black-Scholes pricing model using a weighted average risk-free interest rate of 3.1%, a dividend yield of 0.0%, a weighted average volatility factor of 50.9% and an expected life of 2 years. The Company assigned no value to the purchase warrants issued in 2004.

11. STOCK BASED COMPENSATION

The Company has an Employees and Directors Equity Incentive Plan under which it can grant stock options to directors and eligible employees to purchase common shares, issue common shares to directors and eligible employees for bonus awards and issue shares under a share purchase plan for eligible employees.

Stock options are issued at not less than the fair market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Stock options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Stock options granted after March 1, 1999 vest over four years and expire five to ten years from the date of issue.
Following is a summary of the stock option portion of the Company s Equity Incentive Plan, including changes during the years ended:

	December 31, 2005		December 31, 2004		December 31, 2003	
	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)
Outstanding at beginning of year	8,246	$ 2.65	8,949	$ 2.64	10,265	$ 2.69
Granted	3,664	$ 2.84	608	$ 2.52	840	$ 4.95
Exercised	(111)	$ 1.52	(975)	$ 2.43	(1,363)	$ 3.39
Cancelled/forfeited	(1,521)	$ 6.14	(336)	$ 2.96	(793)	$ 4.42
Outstanding at end of year	10,278	$ 2.21	8,246	$ 2.65	8,949	$ 2.64
Options exercisable at end of year	6,547	$ 1.74	6,698	$ 2.44	6,974	$ 2.20

The Company accounts for all stock options granted using the fair value based method of accounting. This method was adopted retroactively effective January 1, 2004 for stock options granted to employees and directors after January 1, 2002. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. The Company estimated a 24% and 20% forfeiture rate for stock options for 2005 and 2004, respectively, for purposes of calculating the fair value on the date stock options are granted. Revisions in forfeiture estimates are reflected as a change in accounting estimate in the period in which the revision occurs.
For the years ended December 31, 2005, 2004 and 2003 the Company s stock based compensation was $2.1 million, $1.3 million and $0.5 million, respectively.
The foregoing was calculated in accordance with Black-Scholes options pricing model. The weighted average grant-date fair value of stock options granted during 2005, 2004 and 2003 was Cdn.$1.72, Cdn.$1.95 and Cdn.$3.99, respectively. The fair value of the stock options granted was estimated with the following weighted average assumptions for the years presented:

	2005	2004	2003
Assumptions used:			
Risk-free interest rate	3.5%	4.0%	4.1%
Dividend yield	0.0%	0.0%	0.0%
Volatility factor	77.3%	107.6%	99.4%
Expected life (years)	4.0	4.0	4.0

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2005:

Stock Options Outstanding	Stock Options Exercisable

Range of Exercise Prices (Cdn.$)	Number Outstanding (thousands)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price (Cdn.$)	Number Exercisable (thousands)	Weighted-Average Exercise Price (Cdn.$)
$0.50 to $2.00	4,178	2.7	$ 0.62	4,022	$ 0.57
$2.18 to $3.62	5,271	3.7	$ 2.92	1,972	$ 3.00
$5.37 to $7.00	829	2.5	$ 5.73	553	$ 5.73
$0.50 to $7.00	10,278	3.2	$ 2.21	6,547	$ 1.74

12. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (**401(k) Plan**) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) were matched 90% by the Company in 2005 and are planned to increase to a maximum of 100% in 2006. The Company s matching contributions to the 401(k) Plan were $0.3 million for the year ended December 31, 2005 and $0.2 million for each of the years ended December 31, 2004 and 2003.

13. SEGMENT INFORMATION

The Company has three reportable business segments: Oil and Gas, GTL and EOR.

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. The Company does not currently own or operate any GTL projects but in the fourth quarter of 2005 entered into an MOU with Egyptian National Gas Holding Company to prepare a feasibility study to construct and operate a GTL plant in Egypt. Plant capacity options of 45,000 and 90,000 barrels per day will be evaluated.

EOR

The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. The most significant element of the Company s EOR segment is the application of the RTP™ Technology to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. In addition, an RTP™ facility can yield surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the RTP™ process provides heavy-oil producers with an alternative to natural gas that now is widely used to generate steam.

The Company maintains a corporate office in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate**.** The accounting policies of the segments are the same as those disclosed in Note 2.

	Year ended December 31, 2005					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 14,069	$ 15,731	$	$	$	$ 29,800
Interest income	30	7			102	139
	14,099	15,738			102	29,939
Operating costs	5,001	2,602				7,603
General and administrative	1,178	2,076			6,275	9,529
Business and product development			1,307	3,671		4,978
Depletion and depreciation	5,039	9,378	11	13	6	14,447
Interest expense and financing costs	311			4	943	1,258
Write-downs and provision for impairment		5,000	279	357		5,636
	11,529	19,056	1,597	4,045	7,224	43,451
Net (Income) Loss	$ (2,570)	$ 3,318	$ 1,597	$ 4,045	$ 7,122	$ 13,512

Capital Investments	$ 6,541	$ 30,722	$ 1,056	$ 4,982	$	$ 43,301
Identifiable Assets (As at December 31, 2005)	$ 48,070	$ 65,020	$ 14,609	$ 107,869	$ 5,309	$ 240,877

	Year ended December 31, 2004					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 9,311	$ 8,484	$	$	$	$ 17,795
Interest income	10	16			176	202
	9,321	8,500			176	17,997
Operating costs	3,159	1,914				5,073
General and administrative	990	960			5,325	7,275
Business and product development			1,471	442		1,913
Depletion and depreciation	4,594	2,864	16	4	4	7,482
Interest expense	195				184	379
Write-downs and provision for impairment	16,350		250			16,600
	25,288	5,738	1,737	446	5,513	38,722
Net (Income) Loss	$ 15,967	$ (2,762)	$ 1,737	$ 446	$ 5,337	$ 20,725
Capital Investments	$ 17,428	$ 26,965	$ 95	$ 1,966	$	$ 46,454
Identifiable Assets (As at December 31, 2004)	$ 48,465	$ 44,960	$ 13,867	$ 2,441	$ 8,753	$ 118,486

	Year ended December 31, 2003					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 5,466	$ 4,103	$	$	$	$ 9,569
Interest income	19				71	90
	5,485	4,103			71	9,659
Operating costs	2,313	1,980				4,293
General and administrative	2,109	1,176			3,595	6,880
Business and product development			1,331			1,331
Depletion and depreciation	2,321	1,484	20		4	3,829
Interest expense	115	27			42	184
Write-down and provision for impairment	20,000		3,321			23,321
	26,858	4,667	4,672		3,641	39,838

Net Loss	$ 21,373	$ 564	$ 4,672	$	$ 3,570	$ 30,179
Capital Investments	$ 8,386	$ 6,213	$ 792	$	$	$ 15,391

14. DERIVATIVE ACTIVITIES

The Company s results of operations are sensitive mainly to fluctuations in oil and natural gas prices. 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 entered into costless collar derivatives to hedge its cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. The derivatives had ceiling prices of $30.45 and $28.95 per barrel for the June 2003 and October 2002 contracts, respectively, and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. Gains and losses on derivatives were recognized in the results of operations as realized. For the year ended December 31, 2003, the Company had realized losses of $0.3 million on derivative transactions. The derivative losses are included in oil and gas revenue.

For the years ended December 31, 2005 and 2004 the Company had no hedging activity.

15. PROVISION FOR IMPAIRMENT

The Company impaired its China oil and gas properties $5.0 million for the year ended December 31, 2005. As a result of production decline performance and drilling results from the wells drilled in the northern blocks of the Dagang field, the Company reduced its estimate of the overall field development program and revised the total proved reserves downward. Additionally, the Company impaired 70% of its costs incurred in the Zitong block due to an unsuccessful first exploration well resulting in those costs being included with the carrying value of proved properties for the ceiling test calculation. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31. 2005	
	West Texas Intermediate (per Bbl)	Henry Hub (per Mcf)
2006	$ 57.00	$ 10.50
2007	$ 55.00	$ 8.75
2008	$ 51.00	$ 7.50
2009	$ 48.00	$ 7.00
2010	$ 46.50	$ 6.75
2011	$ 45.00	$ 6.50
2012	$ 45.00	$ 6.50
2013	$ 46.00	$ 6.65
2014	$ 46.75	$ 6.75
2015	$ 47.75	$ 6.90
2016	$ 48.75	$ 7.05
Thereafter	2% per year	2% per year

The Company impaired its U.S. oil and gas properties $16.3 million for the year ended December 31, 2004 due to the evaluation of a number of its unproved properties, primarily in California, plus the impairment of its producing fields at Knights Landing, Citrus and the southern expansion at South Midway as costs incurred to add new reserves exceeded the expected future cash flows from those properties. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31. 2004	
	West Texas Intermediate (per Bbl)	Henry Hub (per Mcf)
2005	$ 42.00	$ 6.20
2006	$ 40.00	$ 6.00
2007	$ 38.00	$ 5.75
2008	$ 36.00	$ 5.50
2009	$ 34.00	$ 5.50
2010 to 2015	$ 33.00 to $34.50	$ 5.50 to $5.75
Thereafter	2% per year	2% per year

The $20.0 million provision for impairment for the year ended December 31,2003 was due mainly to an increase in the carrying costs of the Company s evaluated U.S. oil and gas properties primarily in East Texas, Northwest Lost Hills and other California prospects when compared to the estimated recoverable value of its U.S. proved reserves as at December 31, 2003. Such carrying costs increased as a result of the decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of the Company s working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally, evaluation of significant portions of the Company s acreage positions in East Texas and the southern San Joaquin Basin in California was completed in 2003 and were relinquished thus adding to the carrying value of the Company s proved U.S. oil and gas properties. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31. 2003	
	West Texas Intermediate	**Henry Hub**
	(per Bbl)	(per Mcf)
2004	$ 29.00	$ 5.10
2005	$ 26.00	$ 4.50
2006	$ 25.00	$ 4.35
2007	$ 25.00	$ 4.35
2008	$ 25.00	$ 4.35
2009 to 2014	$ 25.00	$ 4.35
Thereafter	1.5% per year	1.5% per year

16. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rate to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2005, 2004 and 2003 were 33.6%, 33.6% and 43.2%, respectively. The sources and tax effects for the differences were as follows**:**

	Year ended December 31,		
	2005	2004	2003
Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates	$ (4,543)	$ (6,968)	$ (12,832)
Effect of change in effective income tax rates on future tax assets		(488)	
Foreign net losses affected at lower income tax rates	1,457	(246)	3,251
Expiry of tax loss carry-forwards	1,734	977	569
Effect of change in foreign exchange rates	(659)	(3,433)	(522)
Stock-based compensation not deductible for income tax purposes	756	375	
Tax credit carry-forward	(362)	(1,094)	
Change in prior year estimate of tax loss carry-forwards	(368)	1,756	(239)
Permanent differences related to U.S. royalty interests acquired		1,250	710
Other	16	(5)	170
	(1,969)	(7,876)	(8,893)
Valuation allowance	1,969	7,876	8,893
	$	$	$

Significant components of the Company s future net income tax assets and liabilities as at December 31 were as follows:

	As at December 31,			
	2005		2004	
	Future Income Tax		Future Income Tax	
	Assets	Liabilities	Assets	Liabilities
Oil and gas properties and investments	$	$ (19,673)	$	$ (11,560)
Intangibles		(36,746)		
Tax loss carry-forwards	71,774		58,842	
Tax credit carry-forward	1,456		1,094	
Valuation allowance	(16,811)		(48,376)	
	$ 56,419	$ (56,419)	$ 11,560	$ (11,560)

Due to the uncertainty of utilizing these net income tax assets, the Company has made a valuation allowance of an equal amount against the potential recoverable amounts.

The tax loss carry-forwards in Canada are Cdn. $44.2 million and in the U.S. $87.3 million, including $9.6 million tax losses carried forward from Ensyn. The tax loss carry-forwards in Canada expire between 2006 and 2012 and in the U.S. between 2016 and 2025. In China, the Company has available for carry-forward against future Chinese income $68.7 million of cost basis. The loss of approximately Cdn. $55.3 million from the Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

17. NET LOSS PER SHARE

Had the Company generated net earnings during the years presented, the earnings per share calculations for the years presented would have included the following weighted average items:

Year ended December 31,

	(thousands of shares)		
	2005	**2004**	**2003**
Richfirst conversion rights	9,631	9,537	
Stock options	3,211	3,796	3,535
Purchase warrants	862	2,107	556
Convertible debt			499
	13,704	15,440	4,590

Richfirst had the right to exchange its working interest in the Dagang field for common shares in the Company at any time during an eighteen-month period ended December 2005. For purposes of this calculation, the number of the Company s common shares issuable to Richfirst upon conversion were based on Richfirst s initial investment in the Dagang field of $20.0 million converted at the average of the monthly high and low trading prices of the Company s common shares on the Toronto Stock Exchange at the average monthly U.S. dollar to Canadian dollar exchange rates during the eighteen-month period.

Additionally, the earnings per share calculations would not have included the following weighted average items because the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31, (thousands of shares)		
	2005	**2004**	**2003**
Stock options	5,103	3,669	3,802
Purchase warrants	9,689	4,082	140
Convertible debt	1,161		306
	15,953	7,751	4,248

18. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for each of the years ended December 31 was as follows:

	Year ended December 31,		
	2005	**2004**	**2003**
Supplementary Information Regarding Non-Cash Transactions			
Financing activities, non-cash:			
Shares issued for:			
Merger *(Note 20)*	$ 75,000	$	$
Refinance of convertible debt *(Note 7)*	4,000		
Conversion of debt			1,000
	$ 79,000	$	$ 1,000
Cash paid during the year include the following:			
Income taxes	$ 20	$ 3	$ 6
Interest	$ 1,138	$ 317	$ 96
Changes in non-cash working capital items Operating Activities:			
Accounts receivable	$ (1,635)	$ (1,949)	$ (201)
Prepaid and other current assets	16	(403)	282
Accounts payable and accrued liabilities	1,840	1,704	950
	221	(648)	1,031
Investing Activities			
Accounts receivable	(2,982)	(708)	
Prepaid and other current assets	457		
Accounts payable and accrued liabilities	14,547	3,972	(537)
	12,022	3,264	(537)
	$ 12,243	$ 2,616	$ 494

19. 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 $3.0 million, $1.6 million and $1.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. As at December 31, 2005 and 2004, amounts included in accounts payable under these arrangements were $0.3 million and $0.1 million, respectively.

20. MERGER

On April 15, 2005, the Company and Ensyn completed the Merger in which the Company paid $10.0 million in cash and issued approximately 30 million Ivanhoe common shares (**Merger Shares**) in exchange for all of the issued and outstanding Ensyn common shares. Ten million of the Merger Shares issued were deposited in an escrow fund and are being held to secure certain obligations on the part of the former Ensyn stockholders to indemnify the Company for damages in the event of any breaches of representations, warranties and covenants in the Merger Agreement and certain liabilities, including those arising from any failure by Ensyn to meet certain development milestones set out in the Merger Agreement.

As at December 31, 2005, the Company incurred $4.2 million of costs associated with the Merger, including $1.0 million to acquire an option to purchase an additional 5% of EPIL, which expired, unexercised, in January 2005. The total purchase consideration and cost of the Merger was $89.2 million and has been allocated to the net assets acquired from Ensyn as follows:

Purchase Consideration	
29,999,886 shares of Ivanhoe at $2.50 per share.	$ 75,000
Cash	10,000
	85,000
Merger related costs	4,228
Total purchase consideration and cost of the Merger	$ 89,228

Net Assets Acquired	
Cash	$ 21
Non-cash working capital, net	(117)
Oil and gas properties and investments	4,561
Intangible asset	89,759
Asset retirement obligation	(96)
Long term obligation *(Note 9)*	(1,900)
Less : previous investment in EPIL	(3,000)
	$ 89,228

21. ENSYN AGREEMENTS

RTP™ Joint Venture

As part of the Merger, the Company acquired a 50% interest in a joint venture (**RTP™ Joint Venture**), which owned the RTP™ CDF and exclusive right to manufacture RTP™ facilities, at cost plus 25%, or be paid a fixed fee if the RTP™ facilities were manufactured by any party other than the RTP™ Joint Venture. In November 2005, the Company acquired the remaining 50% in the joint venture for $6.75 million, which effectively dissolved the joint venture. Accordingly, 100% of the net assets of the RTP™ Joint Venture were included in the Company s consolidated balance sheet as at December 31, 2005. The Company operates the RTP™ CDF and incurred $1.6 million to operate the RTP™ CDF from the date of the Merger to December 31, 2005, which costs are included in business and product development expenses. The RTP™ CDF generated no revenues from the date of the Merger to December 31, 2005.

In 2003, Ensyn (which changed its name following the Merger to Ivanhoe Energy HTL Inc. (**IE HTL**)) entered into an agreement with Aera Energy LLC (**Aera**) providing for the construction of the RTP™ CDF on Aera s property in California s San Joaquin Basin to demonstrate the commercial viability of the RTP™ Technology. The RTP™ Joint Venture partners agreed to fund the construction of an RTP™ CDF, which is now 100% owned by the Company as discussed above in this Note 21. Within six months after completing the RTP™ CDF s testing and demonstration period, which is currently estimated to be December 31, 2006, the Company is responsible for dismantling the facility and restoring the Aera site to its original condition (See Note 8).

ConocoPhillips Canada Resources Corp.

Under a pre-existing agreement between IE HTL and ConocoPhillips Canada Resources Corp. (**ConocoPhillips Canada**), certain non-exclusive rights to use the RTP Technology for petroleum applications in Canada were granted. ConocoPhillips Canada has the right, through August 2010, to place orders for RTP facilities with input capacity of up to 250,000 barrels-per-day. Should ConocoPhillips Canada install RTP facilities, IE HTL is entitled to receive royalties per barrel after the first 50,000 barrels-per day of feedstock input capacity.

22. SUBSEQUENT EVENTS

In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi for $4.0 million subject to the approval of CNPC and PetroChina. Mitsubishi has the option to increase its participating interest to 20% by paying $0.4 million plus costs per percentage point prior to any discovery, or $8.0 million plus costs for an additional 10% interest after completion and testing of the first well drilled under the farm-out agreement. The January 2004 Dagang field farm-out agreement between the Company and Richfirst provided Richfirst with the right to convert its working interest in the Dagang field for the Company s common shares 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 the Company acquired Richfirst s 40% working interest for $27.4 million consisting of 8,591,434 of the Company s common shares for $20.0 million and a non-interest bearing, unsecured note payable of approximately $7.4 million. The note is payable in 36 equal monthly installments with the initial payment due March 31, 2006. The Company has the right, during the three-year loan repayment period, to require Richfirst to convert the remaining balance of the loan into common shares of Sunwing Energy Ltd (**Sunwing**), the Company s wholly-owned subsidiary, or another company owning all of the outstanding shares of Sunwing, subject to Sunwing or the other company having obtained a listing of its common shares on a prescribed stock exchange.

In February 2006, the Company signed a non-binding MOU regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), an inactive U.S. public corporation. If the merger is completed, CMA will effectively acquire all of the issued and outstanding shares of Sunwing for an aggregate acquisition price of $100 million subject to working capital and long-term debt adjustments at closing. The Company will receive common stock of CMA and it is expected that the Company will own between 75% and 80% of the issued and outstanding shares of CMA after the merger. This transaction is subject to regulatory approval, negotiation of definitive documentation, completion of satisfactory due diligence, board approvals and the approval of CMA shareholders.

23. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company s consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Consolidated Balance Sheets

The application of U.S. GAAP has the following effects on consolidated balance sheet items as reported under Canadian GAAP:

Shareholders Equity and Oil and Gas Properties and Investments

	As at December 31, 2005				
		Shareholders Equity			
	Oil and Gas Properties and Investments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 119,654	$ 296,238	$ 3,820	$ (95,291)	$ 204,767
Adjustments for:					
Reduction in stated capital		74,455		(74,455)	
Stock based compensation		(316)	(3,432)	3,748	
Ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,150)			(8,150)	(8,150)
Depletion adjustments due to differences in provision for impairment	1,562			1,562	1,562
GTL and EOR development costs expensed	(10,712)			(10,712)	(10,712)
U.S. GAAP	$ 103,712	$ 371,735	$ 388	$ (183,298)	$ 188,825

	As at December 31, 2004	
		Shareholders Equity
	Oil and Gas	

	Properties and Investments	Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 86,551	$ 183,617	$ 1,748	$ (81,779)	$ 103,586
Adjustments for:					
Reduction in stated capital		74,455		(74,455)	
Stock based compensation		(300)	(1,660)	1,960	
Ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,650)			(8,650)	(8,650)
Depletion adjustments due to differences in provision for impairment	482			482	482
GTL and EOR development costs expensed	(5,884)			(5,884)	(5,884)
U.S. GAAP	$ 73,857	$ 259,130	$ 88	$ (168,326)	$ 90,892

Shareholders Equity

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.5 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.5 million as at December 31, 2005 and 2004.

For Canadian GAAP, the Company accounts for all stock options granted to employees and directors since January 1, 2002 using the fair value based method of accounting. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. For U.S. GAAP, the Company continues to apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and does not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $3.7 million and $2.0 million in the accumulated deficit as at December 31, 2005 and 2004, respectively, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 expensed under Canadian GAAP.

Oil and Gas Properties and Investments

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 was $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions.

There are certain differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference was in the method of performing ceiling test evaluations under the full cost method of accounting rules. Under Canadian GAAP prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center s carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes. As more fully described in Note 2 Oil and Gas Properties , effective January 2004, Canadian GAAP requires recognition and measurement processes to assess impairment of oil and gas properties using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. In the measurement of the impairment, the future net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate.

In the ceiling test evaluation for U.S. GAAP purposes, future net cash flows from proved reserves using period-end, non-escalated prices and costs, are discounted to present value at 10% per annum and compared to the carrying value of oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for 2005 an impairment provision of $1.7 million was required on its China properties compared to a $5.0 million impairment provision under Canadian GAAP. For the Company s U.S. properties, a $2.8 million impairment was required for 2005 on its U.S. properties compared to no impairment being required for Canadian GAAP. The differences in the ceiling test impairments by period for the U.S. and China properties between U.S. and Canadian GAAP as at December 31, 2005 are as follows:

	Ceiling Test Impairments		**(Increase)**
	U.S. GAAP	**Canadian GAAP**	**Decrease**
U.S. Properties			
Prior to 2004	$ 34,000	$ 34,000	$
2004	15,000	16,350	1,350
2005	2,800		(2,800)
	51,800	50,350	(1,450)
China Properties			

Prior to 2004	10,000		(10,000)
2004			
2005	1,700	5,000	3,300
	11,700	5,000	(6,700)
	$ 63,500	$ 55,350	$ (8,150)

The differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion of $1.6 million and $0.5 million as at December 31, 2005 and 2004, respectively.

As more fully described under Investments in EOR and GTL Projects in Note 2, for Canadian GAAP the Company capitalizes certain costs incurred for GTL and EOR projects subsequent to executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the project s products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in the investments in GTL and EOR assets. For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. As at December 31, 2005 and 2004, the Company capitalized $10.7 million and $5.9 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

Consolidated Statements of Loss

The application of U.S. GAAP had the following effects on net loss and net loss per share as reported under Canadian GAAP:

	Year ended December 31,					
	2005		2004		2003	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ 13,512	$ 0.07	$ 20,725	$ 0.12	$ 30,179	$ 0.20
Stock based compensation expense	(1,788)	(0.01)	(1,173)	(0.01)	(476)	
Provision for impairment	(500)		(1,350)	(0.01)		
Depletion adjustments due to differences in provision for impairment	(1,080)	(0.01)	(316)		(88)	
GTL and EOR development costs expensed, net	4,828	0.02	1,810	0.02	(2,529)	(0.02)
U.S. GAAP	$ 14,972	0.07	$ 19,696	$ 0.12	$ 27,086	$ 0.18
Weighted Average Number of Shares under U.S. GAAP (in thousands)		195,803		167,612		150,154

As more fully discussed under Stock Based Compensation in Note 2, as at January 1, 2004 the Company changed its accounting policy, for Canadian GAAP, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. For U.S. GAAP, the Company continues to apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and does not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $1.8 million, $1.2 million and $0.5 million in the net losses for the years ended December 31, 2005, 2004 and 2003, respectively.

As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the ceiling test evaluation under the full cost method of accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP has resulted in an accumulated net increase in impairment provisions on the Company s U.S. and China oil and gas properties of $8.2 million as at December 31, 2005. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $1.1 million, $0.3 million and $0.1 million in the net losses for the years ended December 31, 2005, 2004 and 2003, respectively.

As more fully described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the years ended December 31, 2005 and 2004, the Company expensed $4.8 million and $1.8 million, respectively, in excess of the Canadian GAAP write-downs during those corresponding years. For the year ended December 31, 2003, the Company expensed $2.5 million less for U.S. GAAP than the write-down recognized for Canadian GAAP.

Stock Based Compensation

Had stock based compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123, Accounting for Stock Based Compensation , the Company s net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Year ended December 31, 2005	2004	2003
Net loss under U.S. GAAP	$ 14,972	$ 19,696	$ 27,086
Stock-based compensation expense determined under the fair value based method for employee and director awards	1,911	1,869	1,682
Pro forma net loss under U.S. GAAP	$ 16,883	$ 21,565	$ 28,768
Basic and diluted loss per common share under U.S. GAAP:			
As reported	$ 0.07	$ 0.12	$ 0.18
Pro forma	$ 0.09	$ 0.13	$ 0.19
Weighted Average Number of Shares under U.S. GAAP (in thousands)	195,803	167,612	150,154
Stock options granted during the period (thousands)	2,889	458	690
Weighted average exercise price	$ 2.41	$ 1.88	$ 4.00
Weighted average fair value of options granted during the year	$ 1.52	$ 1.40	$ 2.83

Stock based compensation for U.S. GAAP was calculated in accordance with the Black Scholes option-pricing model using the same assumptions as used for Canadian GAAP.

Pro Forma Effect of Merger

The Company s U.S. GAAP consolidated results of operations for the year ended December 31, 2005 included a net loss of $2.0 million, or $0.01 per share, associated with the operations acquired from Ensyn after the completion of the Merger on April 15, 2005. Had the Merger been completed on January 1, 2005 or 2004, the pro forma revenue, net loss and net loss per share of the merged entity for the years ended December 31, 2005 and 2004 would have been as follows:

	Year Ended December 31, (unaudited) 2005 Revenue	2005 Net Loss	2005 Net Loss Per Share	2004 Revenue	2004 Net Loss	2004 Net Loss Per Share
As reported	$ 29,939	$ 14,972	$ 0.07	$ 17,997	$ 19,696	$ 0.12
Pro forma adjustments	736	730		371	2,248	
	$ 30,675	$ 15,702	$ 0.07	$ 18,368	$ 21,944	$ 0.12
Weighted Average Number of Shares (in thousands)			204,186			197,612

Consolidated Statements of Cash Flow

As a result of the expensing of GTL and EOR development costs required under U.S. GAAP, the statement of cash flow as reported would result in a cash surplus from operating activities of $3.9 million and $2.0 million for the years ended December 31, 2005 and 2004 and a cash deficiency from operating activities of $2.3 million for the year ended December 31, 2003. Additionally, capital investments reported under investing activities would be $37.8 million, $44.4 million and $14.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Additional U.S. GAAP Disclosures

Oil and Gas Properties and Investments

The categories of costs included in Oil and Gas Properties and Investments , including the U.S. GAAP adjustments discussed in this note were as follows:

	As at December 31, 2005			As at December 31, 2004		
	U.S.	China	Total	U.S.	China	Total
Property acquisition costs	$ 20,613	$ 2,418	$ 23,031	$ 22,295	$ 2,418	$ 24,713
Royalty rights acquired	10,582		10,582	10,582		10,582
Exploration costs	41,289	15,525	56,814	35,120	8,594	43,714
Development costs	38,272	58,861	97,133	35,456	35,105	70,561
Commercial demonstration facility	9,600		9,600			
Support equipment and general property	556	315	871	480	270	750
	120,912	77,119	198,031	103,933	46,387	150,320
Accumulated depletion and depreciation	(16,015)	(14,804)	(30,819)	(11,197)	(6,266)	(17,463)
Provision for impairment	(51,800)	(11,700)	(63,500)	(49,000)	(10,000)	(59,000)
	$ 53,097	$ 50,615	$ 103,712	$ 43,736	$ 30,120	$ 73,857

U.S. development costs as at December 31, 2005, 2004 and 2003 included $1.5 million, $0.6 million and $0.4 million, respectively, of asset retirement costs.

As at December 31, 2005, the costs of unproved properties included in oil and gas properties, which have been excluded from the depletion and ceiling test calculations, were as follows:

		Incurred in			
	Total	2005	2004	2003	Prior to 2003
Property acquisition costs	$ 3,058	$ (247)	$ 621	$ 429	$ 2,255
Royalty rights acquired	659				659
Exploration costs	11,311	5,116	4,493	751	951
	$ 15,028	$ 4,869	$ 5,114	$ 1,180	$ 3,865

The following is a summary of unproved oil and gas properties by prospect for the U.S. and China cost centers as at December 31, 2005:

		Incurred in			
	Total	2005	2004	2003	Prior to 2003
U.S.					
LAK Ranch	3,275	1,221	2,054		
North Yowlumne	1,469	292	347	507	323
East Texas	903	(59)	51	7	904
Knights Landing	1,848	1,848			
San Joaquin Basin prospects other	2,213	60	193	22	1,938
	9,708	3,362	2,645	536	3,165
China					
Zitong block	5,320	1,507	2,469	644	700

	$ 15,028	$ 4,869	$ 5,114	$ 1,180	$ 3,865

Evaluation of the North Yowlumne, East Texas and Zitong block prospects will be conducted during 2006 with the completion of drilling and/or testing of exploration wells planned or in process. In addition, the Company expects to complete its evaluation of the production response to the continuous steam injection pilot program at the LAK Ranch field during 2006 and decide whether or not to proceed with the next phase of field development using enhanced oil recovery techniques. The Company expects to complete significant or full evaluations of the aforementioned properties in 2006 at which time their costs will be included in the depletion and ceiling test calculations, as appropriate.

Accounts Payable and Accrued Liabilities

The following was the breakdown of accounts payable and accrued liabilities:

	As at December 31,	
	2005	**2004**
Accounts payable and accruals	$ 23,955	$ 8,745
Accrued salaries and related expenses	1,397	929
Accrued interest	22	11
Other accruals	417	160
	$ 25,791	$ 9,845

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

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This statement (**SFAS No. 123(R)**) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company applies APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from its stock option plan and does not recognize compensation costs in its U.S. GAAP financial statements for stock options issued to its employees and directors. This statement is effective for the first fiscal year that begins after June 15, 2005 and may be implemented on a modified prospective or retrospective basis. The Company has elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis the Company would recognize stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as at January 1, 2006 and for all awards granted after January 1, 2006. The Company expenses stock based compensation in its financial statements for Canadian GAAP and expects that the impact of implementing SFAS 123(R) will not be materially different for U.S. GAAP purposes.

To assist in the implementation of SFAS No. 123(R), the SEC issued SAB No. 107, Share-Based Payment (**SAB No. 107**). While SAB No. 107 addresses a wide range of issues, the largest area of focus is valuation methodologies and the selection of assumptions. Notably, SAB No. 107 lays out simplified methods for developing certain assumptions. In addition to providing the SEC staff s interpretive guidance on SFAS No. 123(R), SAB No. 107 addresses the interaction of SFAS No. 123(R) with existing SEC guidance (e.g., the interaction with the SEC s guidance dealing with non-GAAP disclosures). Its intent is to clarify, not change, any of SFAS No. 123(R) s guidance.

In May 2005, the FASB issued SFAS No. 154 (**SFAS No. 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 applies to all voluntary changes in accounting principle. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 carries forward without change to the guidance contained in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 also carries forward the guidance in APB Opinion No. 20 requiring justification of a change in accounting principle on the basis of preferability. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

On July 14, 2005, the FASB published an exposure draft entitled Accounting for Uncertain Tax Positions - an interpretation of SFAS No. 109. The proposed interpretation is intended to reduce the significant diversity in practice associated with recognition and measurement of income taxes by establishing consistent criteria for evaluating uncertain tax positions. The proposed interpretation would be effective for the first fiscal year beginning after December 15, 2006. Earlier application would be encouraged. Only tax positions meeting the probable recognition threshold at that date would be recognized. The transition adjustment resulting from application of this interpretation would be recorded as a cumulative-effect change in the income statement as of the end of the period of adoption. Restatement of prior periods or pro forma disclosures under APB Opinion No. 20, Accounting Changes , would not be permitted. The implementation of this exposure draft is not expected to impact the Company at this time. .

On September 30, 2005, the FASB issued an Exposure Draft that would amend SFAS No. 128, Earnings per Share , to clarify guidance for mandatorily convertible instruments, the treasury stock method, contracts that may be settled in cash or shares and contingently issuable shares. The proposed Statement would be effective for interim and annual periods ending after June 15, 2006. Retrospective application would be required for all changes to SFAS No. 128, except that retrospective application would be prohibited for contracts that were either settled in cash to prior adoption to require cash settlement. Management is in the process of reviewing the requirements of this recent exposure draft.

The following standards issued by the FASB are not expected to impact the Company:

SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

FASB issued Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 , effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises).

QUARTERLY FINANCIAL DATA IN ACCORDANCE WITH CANADIAN AND U.S. GAAP (UNAUDITED)

	QUARTER ENDED							
	2005				2004			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Total revenue	$ 8,651	$ 8,907	$ 6,645	$ 5,736	$ 6,212	$ 4,932	$ 3,521	$ 3,332
Net loss:								
Canadian GAAP	$ 8,885	$ 2,113	$ 1,031	$ 1,483	$ 17,184	$ 951	$ 1,298	$ 1,292
U.S. GAAP	$ 8,557	$ 1,843	$ 1,564	$ 3,008	$ 15,736	$ 980	$ 1,510	$ 1,470
Net loss per share:								
Canadian GAAP	$ 0.04	$ 0.01	$ 0.01	$ 0.01	$ 0.09	$ 0.01	$ 0.01	$ 0.01
U.S. GAAP	$ 0.03	$ 0.01	$ 0.01	$ 0.02	$ 0.09	$ 0.01	$ 0.01	$ 0.01

The Canadian GAAP net loss in the fourth quarter of 2005 was primarily due to an impairment provision of $5.0 million for the China oil and gas properties. The U.S. GAAP loss in the fourth quarter of 2005 was primarily due to impairment provisions of $1.7 million and $2.8 million for the China and U.S. oil and gas properties, respectively. The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company s oil and gas producing activities is presented in accordance with U.S. Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities .

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods.

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

Reserves presented in this section represent the Company s share of reserves, excluding royalty interests of others. The reserves were based on the estimates by the independent petroleum engineering firms of Gilbert Laustsen Jung Associates Ltd. and Netherland, Sewell & Associates, Inc. for the China and U.S. reserves, respectively.

The changes in the Company s net proved oil and gas reserves for the three-year period ended December 31, 2005 were as follows:

	Oil (MBbl)			Gas (MMcf)
	U.S.	China	Total	U.S.
Net proved reserves, December 31, 2002	1,784	15,604	17,388	819
Extensions and discoveries	480		480	22
Production	(202)	(144)	(346)	(50)
Revisions to previous estimates	(499)	239	(260)	(96)
Net proved reserves, December 31, 2003	1,563	15,699	17,262	695
Extensions and discoveries	240		240	1,289
Purchases of reserves in place				819
Production	(234)	(235)	(469)	(207)
Revisions to previous estimates	(121)	(1,360)	(1,481)	87
Sale of reserves	(18)	(6,196)	(6,214)	
Net proved reserves, December 31, 2004	1,430	7,908	9,338	2,683
Extensions and discoveries	19		19	98
Production	(237)	(315)	(552)	(495)
Revisions to previous estimates	60	(6,293)	(6,233)	(601)
Net proved reserves, December 31, 2005	1,272	1,300	2,572	1,685
Net proved developed reserves as at:				
December 31, 2003	1,225	209	1,434	695
December 31, 2004	1,187	1,142	2,329	2,365
December 31, 2005	1,099	1,071	2,170	1,405

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

The following standardized measure of discounted future net cash flows from proved oil and gas reserves was computed using period end statutory tax rates, costs and prices of $55.77, $40.25 and $30.31 per barrel of oil in 2005, 2004 and 2003, respectively, and $9.80, $5.94 and $6.13 per Mcf of gas in 2005, 2004 and 2003, respectively. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

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

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future, rather than year end, prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

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

	2005		
	U.S.	China	Total
Future cash inflows	$ 83,418	$ 76,533	$ 159,951

Future development and restoration costs	2,890	8,136	11,026
Future production costs	32,699	12,828	45,527
Future income taxes		1,584	1,584
Future net cash flows	47,829	53,985	101,814
10% annual discount	15,655	10,686	26,341
Standardized measure	$ 32,174	$ 43,299	$ 75,473

	2004		
	U.S.	China	Total
Future cash inflows	$ 64,357	$ 327,481	$ 391,838
Future development and restoration costs	3,063	84,682	87,745
Future production costs	27,867	58,488	86,355
Future income taxes		44,708	44,708
Future net cash flows	33,427	139,603	173,030
10% annual discount	11,238	50,774	62,012
Standardized measure	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	China	Total
Future cash inflows	$ 48,751	$ 478,748	$ 527,499
Future development and restoration costs	2,138	154,245	156,383
Future production costs	22,037	91,912	113,949
Future income taxes		61,647	61,647
Future net cash flows	24,576	170,944	195,520
10% annual discount	7,466	89,180	96,646
Standardized measure	$ 17,110	$ 81,764	$ 98,874

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

	2005		
	U.S.	China	Total
Sale of oil and gas net of production costs	$ (9,068)	$ (13,129)	$ (22,197)
Net changes in pricing and production costs	15,110	20,016	35,126
Discoveries and extensions	1,051		1,051
Revisions of previous estimates	(1,492)	(150,588)	(152,080)
Net change in income taxes		24,993	24,993
Net change in future development costs	(694)	46,380	45,686
Accretion of discount	5,078	26,798	31,876
Increase (decrease)	9,985	(45,530)	(35,545)
Standardized measure, beginning of year	22,189	88,829	111,018
Standardized measure, end of year	$ 32,174	$ 43,299	$ 75,473

	2004		
	U.S.	China	Total
Sale of oil and gas net of production costs	$ (6,152)	$ (6,570)	$ (12,722)
Net changes in pricing and production costs	1,015	56,329	57,344

Sale of reserves	(108)	(21,646)	(21,754)
Discoveries and extensions	6,779		6,779
Purchases of reserves in place	3,050		3,050
Revisions of previous estimates	(1,401)	(22,847)	(24,248)
Net change in income taxes		(9,107)	(9,107)
Net change in future development costs	(1,700)	(14,424)	(16,124)
Accretion of discount	3,596	25,330	28,926
Increase	5,079	7,065	12,144
Standardized measure, beginning of year	17,110	81,764	98,874
Standardized measure, end of year	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	**China**	**Total**
Sale of oil and gas net of production costs	$ (3,153)	$ (2,123)	$ (5,276)
Net changes in pricing and production costs	(4,034)	47,960	43,926
Discoveries and extensions	5,712	(636)	5,076
Revisions of previous estimates	(8,957)	1,604	(7,353)
Net change in income taxes		(9,435)	(9,435)
Net change in future development costs	2,337	(14,626)	(12,289)
Accretion of discount	3,720	(762)	2,958
Increase (decrease)	(4,375)	21,982	17,607
Standardized measure, beginning of year	21,485	59,782	81,267
Standardized measure, end of year	$ 17,110	$ 81,764	$ 98,874