IVANHOE ENERGY INC
Form 10-K
March 20, 2003

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

x	Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the fiscal year ended December 31, 2002.
or	
o	Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the transition period from

to ------------------------------ .
Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada

(State or other jurisdiction of incorporation or organization)

98- 0372413

(I.R.S. Employer Identification No.)

654 999 Canada Place

Vancouver, British Columbia, Canada
V6C 3E1
(Address of principal executive offices)

(604) 688-8323

(Registrant s telephone number, including area code)

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

Securities registered or to be 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	The Toronto Stock Exchange NASDAQ SmallCap Market

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 x 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. x

Indicate by check mark whether the registrant is an accelerated filer as defined in Rule 12b-2 of the Act.

Yes x No o

The aggregate market value of the voting stock held by non-affiliates of the Registrant on June 28, 2002 based on the closing price on the NASDAQ National Market on that date, was $121,378,767.

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 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:

	2002	2001	2000	1999	1998
Closing	$0.63	$0.63	$0.67	$0.69	$0.65
Low	$0.64	$0.62	$0.64	$0.64	$0.63
High	$0.64	$0.67	$0.70	$0.69	$0.71
Average Noon	$0.63	$0.65	$0.67	$0.67	$0.67

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 March 3, 2003 was $0.67 ($1.00 = Cdn.$1.485). Exchange rates are based upon the noon buying rate in New York City for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York.

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Bbls/d	= barrels per day
Boe/d	= 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 standard in which one Bbl is equal to six Mcf.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are forward-looking statements . 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 operations in the U.S. and China; our limited cash resources and consequent need for additional financing; uncertainties regarding the potential success of our oil and gas exploration and development projects in the U.S. and China; uncertainties regarding the potential success of gas-to-liquids technology; 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 , will , expect , intend , estimate , anticipate , believe or continue or the negative thereof or variations thereon terminology.

ENFORCEABILITY OF CIVIL LIABILITIES

We have been 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 Form 10-K Annual Report 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 and officers or experts named in this Form 10-K Annual Report.

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 international energy company engaged in the development of gas-to-liquids projects, enhanced recovery and conventional exploration and production. We were incorporated pursuant to the laws of the Yukon Territory, Canada, on February 21, 1995 under the name 888 China Holdings Limited. We were largely inactive until early 1996. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our 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 offices are located at Suite 654 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records offices are located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

HISTORICAL OVERVIEW

Ivanhoe Energy Inc. is a company focused on three major strategies: (1) production of clean fuels from natural gas using gas-to-liquids (GTL) technology; (2) enhanced oil recovery (EOR) and natural gas projects, on a production-sharing basis, with national petroleum companies and (3) conventional exploration and production (E&P), primarily natural gas in the U.S.

Following our incorporation in February 1995, we were largely inactive until early 1996. Initially, our strategy was to seek out existing oil and gas properties in Russia on which past field development practices did not maximize reserve recoveries and to establish joint ventures with local partners to enhance oil recovery. However, after successfully increasing oil production and reserves at the Kalchinskoye field in western Siberia, a dispute with our partner prevented us from proceeding with operations in the area. In August 2000 we settled the dispute and disposed of our assets for approximately $29 million, bringing to an end our activities in Russia.

In the third quarter of 1998, we began to implement a diversification program aimed at expanding the geographical scope of our business. We added three individuals to our Board of Directors who have international experience in the oil and gas industry. David Martin, who is now our Chairman, was formerly the President and CEO of Occidental Oil and Gas Corporation. E. Leon Daniel, who is now our President and CEO, and John Carver, who is now one of our directors, are also both former executives of Occidental Oil and Gas Corporation.

In August 1998, we began acquiring oil and gas exploration property interests in Peru, which we relinquished in 2000 after our exploration test well was unsuccessful.

In California, we started accumulating working interests and royalty interests in the San Joaquin Valley in 1998, primarily through an exploration agreement with Aera Energy LLC (Aera). This agreement entitled us to joint explorations rights with Aera in return for analyzing and identifying oil and gas prospects. Under the agreement, we had access to exploration, seismic and technical data owned by Aera. See Oil and Gas Properties California

In June 1999, we expanded the geographical scope of our business into China by acquiring Sunwing Energy Ltd. (Sunwing), an oil and gas E&P company. As a result of our merger with Sunwing, we acquired two production-sharing contracts with China National Petroleum Corporation (CNPC) to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing in the Heilongjiang Province. We subsequently sold our working interest in our Daqing oil and gas properties in January 2002 so we could concentrate our Chinese efforts in the larger and more prospective Dagang area.

In April 2000, we acquired a limited volume license from Syntroleum Corporation (Syntroleum) to use its proprietary GTL technology to convert natural gas into synthetic fuels. By sponsoring engineering and design work to extend the Syntroleum technology for large-scale and more economical gas conversion, we earned the right to upgrade our limited volume license to a master license. The master license allows us to use Syntroleum s proprietary process to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. We plan to use the technology in areas with large natural gas deposits, which would otherwise be uneconomic to develop.

Our master license entitles us to use the Syntroleum proprietary process in an unlimited number of GTL projects throughout the world, excluding North America, China and India.

Immediately following the Syntroleum Master License acquisition, we began actively pursuing development contracts for GTL plants in Qatar, Egypt and Oman, and have undertaken extensive feasibility studies in connection with these opportunities. Our negotiations with Qatar Petroleum for a development and production-sharing contract are currently at an advanced and detailed stage. See Gas-to-Liquids Projects .

In May 2000, we entered into an agreement with Discovery Operating, Inc. (Discovery) to earn working interests in approximately 10,000 gross acres of oil and gas exploration properties in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. We sold interests in the least productive of our Spraberry wells in 2002, limiting our remaining holdings to interest in only 25 producing wells and approximately 2,200 gross acres.

During 2000 and 2001 we leased the mineral rights in approximately 49,000 gross acres in the East Texas Basin and in 2001 entered into a joint venture agreement with a subsidiary of Unocal Corp. (Unocal) to explore and develop prospects in the Bossier Trend. See Oil and Gas Properties Texas .

In February 2001, we extended our China interests. We entered into two memoranda of understanding with PetroChina Corporation (PetroChina), a subsidiary of CNPC, which gives us the exclusive right to negotiate production-sharing contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. In September 2002, we signed a 30-year production-sharing contract for two of these blocks covering approximately 900,000 acres and are waiting further response from PetroChina to begin negotiations on the third block. The Sichuan Basin is a major oil and gas producing region of China located approximately 930 miles southwest of Beijing. See Oil and Gas Properties China .

CORPORATE STRATEGY

Our mission is to increase shareholder value by developing business opportunities in 1) GTL conversion projects using our licensed Syntroleum technology, 2) EOR development projects, and 3) E&P projects. In pursuing these three business development areas, we are focused on achieving a balance in our short, medium and long-term goals. Our long-term priority is on GTL production of ultra clean fuels. Our medium term strategy is to concentrate on natural gas exploration and development. Short term, we are focused on EOR and E&P projects that can be implemented and achieve early production and cash flow. During 2002 these strategies continued to mature and gain focus.

Our long-term objective 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 and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant construction is less expensive and the plant is safer to operate because, unlike competing technologies, the conversion process utilizes compressed air rather than pure oxygen.

With our master license to use Syntroleum s proprietary GTL technology, we are currently pursuing opportunities in Qatar, Egypt and Oman to obtain rights to stranded natural gas deposits to use as feedstock for GTL projects.

The cornerstone of our medium term strategy is exploration and development in the San Joaquin Basin of California and in East Texas. In 1998, we acquired exploration rights through an agreement with Aera, California s largest producer. This agreement gave us access to a significant inventory of exploration, seismic and technical data for the purpose of identifying drillable prospects, primarily beneath existing oil fields in the San Joaquin Basin.

Our activities in China also have the potential to contribute to our medium-term growth. In September 2002, Sunwing entered into a 30-year production-sharing contract with PetroChina in the western portion of the Sichuan Basin. Under the terms of the agreement, Sunwing will develop natural gas deposits on the 900,000 acre Zitong Block. Sunwing has established crude oil production at its Dagang project. We remain encouraged by the results achieved in our production program at Dagang and intend to proceed with the development phase once Chinese government authorities approve our development plan. Based on our decision to concentrate on larger projects in China, we decided to dispose of our smaller Daqing project. For a further description of our E&P and EOR projects in the U.S. and China, see Oil and Gas Properties .

Our short-term objective is to focus on areas where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established oil and natural gas production in the South Midway property in the San Joaquin Basin of California, in the Spraberry Trend of West Texas, and at Dagang in China.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum s proprietary GTL process in an unlimited number of projects in all areas of the world, other than North America, China and India, with no limit on production volume.

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 cost 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. 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, 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 Prospects

During 2001, we undertook detailed project feasibility studies for the construction, operation and cost of GTL plants in both Qatar and Egypt. The scope of our proposed project in Qatar includes the development of natural gas from the North Field, transporting that gas to shore, extracting the associated liquids in a natural gas liquids (NGL) plant, moving the dry gas though the GTL facility to create diesel and naphtha and storing and offloading the products for shipment throughout the world. Under this proposal we intend to produce 121,000 barrels of NGL, such as condensate, propane, butane and ethane and 185,000 barrels of GTL product per day. This proposal would also provide 220,000 barrels of agricultural quality water per day. This proposal contemplates the largest facility of its kind in the world with an estimated total cost of approximately $5 billion. Negotiations with Qatar Petroleum (QP) and the Government of the State of Qatar have been ongoing for several months following the completion of feasibility studies. Technical and financial due diligence has been completed and a Heads of Agreement is being negotiated.

The feasibility studies we have undertaken for Egypt contemplate the natural gas feedstock being purchased, rather than developed, and production capacity in the order of 45,000 barrels per day. The results of the feasibility studies are being utilized during the course of commercial discussions with Egyptian authorities. We are still at the early stages of discussion with the Government of Oman for a GTL project.

We have conducted marketing and transportation feasibility studies for both Europe and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL, diesel and naphtha. Based on our ongoing commercialization studies and the growing demand for cleaner sources of energy in Japan, we have incorporated a new subsidiary in Japan to facilitate the potential future participation by Japanese companies in the Qatar GTL project. Should we obtain the right to develop this project, we intend to assign up to 5% of our interest to our new Japanese subsidiary, GTL Japan Corporation (GTLJ). GTLJ would then invite Japanese companies from the refining and distribution, exploration and production, trading and manufacturing industry sectors to invest in GTLJ. The proceeds raised would be used to fund up to an estimated $250 million of project costs, including front-end engineering and design.

Sweetwater GTL Project

In 2000, we signed a letter of intent to invest $21.0 million to participate as a 13% partner in Syntroleum s Sweetwater GTL project in Western Australia. The project was a 10,000 barrels per day plant that would produce specialty products such as lubricants, industrial fluids and liquid normal paraffin, as well as synthetic fuels. We made a $2.0 million advance for front-end engineering and other costs. The balance of the investment was subject to a number of conditions, including Syntroleum s obligation to arrange project financing.

During 2002, the project was cancelled by Syntroleum. In June 2002, we signed a letter of intent with Syntroleum to participate in its U.S. Department of Energy (DOE) Fuels Project at a cost of $5.0 million. Our participation is contingent upon our success in signing a GTL

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project contract in Qatar. Our cost of participating in the DOE Fuels Project is to be offset by $2.0 million of our investment in Sweetwater.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in the San Joaquin Valley area of California, the Midland and East Texas Basins in Texas and the Hebei Province in China. Set forth below is a description of our material oil and gas properties.

California

Over the past five years, we have acquired interests in a number of properties in and around the San Joaquin Basin. To date, only our South Midway project contains proved reserves and has 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

In 1998, we acquired rights to an exploration agreement with Aera covering an area of more than 250,000 acres in the San Joaquin Valley. The Aera exploration agreement gave us access to all of Aera s exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects within the exclusive area. We have a right to a working interest ownership in, and Aera has the right to act as the operator for, any drillable prospects in which Aera elects to participate.

Except for those prospect areas of mutual interest (AMIs) previously designated by us and accepted by Aera, our exclusive rights to explore Aera s properties expired in September 2001. We will continue to hold exploration rights to the lands within previously designated and accepted prospect AMIs until an exploration well is drilled in that prospect. Although the Aera exploration agreement provides that Aera s working interest in these prospects will range from a minimum of 25% to a maximum of 87.5%, we have negotiated different working interest allocations with Aera. Aera is obliged to assign to us any working interest in the prospect that it does not retain. Once we identify a drillable prospect and agree upon working interests with Aera, we have an indefinite time to carry out exploration drilling if Aera elects to participate in the prospect. If Aera elects to participate but not to drill the designated prospect, or 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.

The properties covered by the Aera exploration agreement are located in Kern, Kings, Tulare, Fresno, San Benito, Monterey and San Luis Obispo Counties. Using the extensive proprietary seismic and technical databases owned by Aera and supplemented by us, we have identified 30 prospects within 12 prospect AMIs covering approximately 76,000 gross acres. Of the 12 prospect AMIs we have submitted, Area has elected to take a working interest in 9 areas, in which we have working interests ranging from 12.5% to 50% and we have a 100% working interest in three prospect AMIs in which Aera elected not to participate.

South Midway

Our first project under the Aera exploration agreement was in the South Midway field, in which Aera elected not to participate. We therefore own a 100% working interest and a 93% net revenue interest in the project. Aera receives royalties pursuant to our exploration agreement. By the end of 2002, we had drilled 41 wells, 35 of which are producing oil wells. We are currently producing approximately 525 gross barrels per day a slight decline from the peak production level of 625 gross barrels per day achieved in the fourth quarter of 2002. We implemented a full-scale cyclic steam injection project during 2002, which provided for more than a 300 gross barrel per day increase in production levels. Our drilling in the South Midway area has identified additional new pools in the field, and based on this success, we have arranged a $5.0 million credit facility to fund an additional 20 wells and cyclic steam expansion program that is expected to provide additional production volume increases during the second half of 2003.

Belgian Anticline

The second exploratory prospect was a gas test in the Belgian Anticline field area. The well found the prospective gas sands, but they had been partially depleted by other nearby wells.

Northwest Lost Hills

The third exploration prospect area was at Northwest Lost Hills where we began drilling in August 2001 the Northwest Lost Hills #1-22 well, located in Kern County and operated by Aera. The well lies five miles northwest of, and on a trend with, the Bellevue No. 1 gas discovery drilled by Berkley Petroleum Corp. In the 9,300 gross acres owned and under option encompassing the Northwest Lost Hills prospect, we hold, on average, a 39% working interest. We have a 42% working interest in the NWLH #22-1 well.

The well was designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reach a depth of approximately 20,000 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 decided to set casing in preparation for testing. Testing operations have been suspended while we seek a partner to share the costs of the testing program. Accordingly, the commercial success of this well has not yet been determined.

Other Southern California Prospects

Amethyst Prospect

The next prospect we are likely to drill is in the northern part of the South Belridge area, which we have designated Amethyst. We currently hold a 15% working interest in the prospect. We originally expected to commence drilling the prospect in early 2002, but delayed drilling in order to shoot and evaluate additional seismic data. We have completed interpreting this additional seismic data and expect to begin drilling this prospect during 2003.

North South Forty

In 1999, we entered into an agreement with Prime Natural Resources, LLC (Prime) to jointly conduct a 3-D seismic survey in the southern San Joaquin Valley basin in order to identify new prospects over an area of approximately 80,000 acres. We subsequently entered into an exploration agreement with Prime and Aera in which we agreed to pool certain of our acreage positions in the basin to share the costs of carrying out the 3-D seismic program and to broaden our respective interests in the area. All costs of carrying out the program will be borne equally by Prime and Ivanhoe. The 3-D seismic program is intended to identify prospects for exploration drilling. Once prospects have been identified, each party may elect to participate in a drilling program. We started evaluating the results of the program in the second half of 2001 and to date three drillable prospects have been identified. Our evaluation remains ongoing while we look for potential farm-in candidates for these prospects. Our working interests over this exploration area currently range from 17.5% to 50%.

Texas

Spraberry

In May 2000, we entered into an agreement with Discovery Operating, Inc. (Discovery) to earn working interests in approximately 10,000 gross acres of oil and gas exploration property in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. During 2002, after determining that most of the wells producing in the Spraberry Trend contained little upside for reservoir and production enhancements, we elected to sell a majority of our interests in these wells. These sales generated cash proceeds of approximately $3.0 million. We currently have a working interest of 31% in 16 wells and 48% in 4 wells on approximately 1,760 gross acres. We retained our interests in the Apache Flats area because the wells in that area have shown higher levels of daily production. We hold a 40% working interest in 5 wells in Apache Flats on approximately 400 gross acres covered by a farm-out agreement. Following the property sales, we are producing approximately 120 net Boe/d from the 25 wells in West Texas. Discovery is the operator of the West Texas Properties.

East Texas

We have leased mineral rights in approximately 49,000 gross acres in East Texas under a joint venture with Unocal. Unocal is the operator of the joint venture and will fund the drilling costs for the first several exploration wells to offset the $10.1 million in leasehold, seismic and processing costs we have already incurred. After our respective investments in the joint venture have been equalized, we will share exploration, development and infrastructure costs equally.

In late 2001, and during the first half of 2002, three exploratory wells were drilled. During drilling, indications of natural gas were encountered from multiple pay sands such as the Bossier, Cotton Valley and Pettit but no commercial levels of production were established. The drilling costs for these wells were carried by our 50% partner, Unocal, as a part of the agreement for their participation. Since mid-2002, our activities in East Texas have been very limited. Early in 2003, we reached an agreement with a third party to further test the potential for natural gas production from the Rodessa and Pettit Sands in two of the wells drilled on the Creslenn Ranch Prospect in Henderson County. We continue to search for third parties to fund our share of exploration in the remaining prospects in East Texas.

Kentucky

In March of 2001, we entered into a joint venture with Hay Exploration, Inc. to explore for natural gas in the Rome Trough of eastern Kentucky. We each held a 50% interest. We identified three prospect areas covering 15,000 net acres and during 2001 we drilled an exploration well in each prospect area. However, based on our assessment that these prospects contain no commercial quantities of gas, we relinquished our participation in these properties to Hay and have no further obligations on these prospects.

China

We hold interests in China through our wholly owned subsidiary Sunwing Energy Ltd.

Daqing Project

Our first project in China was Daqing, a production-sharing contract with CNPC, which covered an area of 8,100 gross acres in the Zhaozhou oilfield in Daqing, Heilongjiang Province, China (the Daqing Project). We initially undertook the Daqing Project on the expectation that we would be able to acquire rights to additional land blocks. We were unable to acquire the additional blocks necessary to provide critical mass and divested our interest in January 2002 for $2.4 million and a right to an overriding royalty on future production.

Dagang Project

Sunwing s producing asset in China is a 20-year production-sharing contract with CNPC, covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the Dagang Project). Under the contract we operate the project and 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%.

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 over the past three years has averaged approximately $2.00 per barrel less than the West Texas Intermediate (WTI) price.

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 Project 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 Project will revert to CNPC at the end of the 20-year production period or if we abandon the project earlier.

In 1999, we farmed out a 20% working interest in the Dagang project to Nippon Oil Exploration Limited (Nippon) for which Nippon agreed to fund $6.0 million of pilot testing expenditures. At the end of the pilot phase, Nippon elected to relinquish its 20% working interest back to us.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of an Overall Development Program (ODP) to Chinese regulatory authorities for approval. Our partner, PetroChina, has approved the program, and has recommended to the Central Government that we be allowed to proceed with the development. We expect to receive this Government approval during the first half of 2003, after which the development phase will commence. The current development program will cost approximately $185.0 million over a three-year period and will involve drilling 115 new wells and reworking an additional 29 of the 82 existing wells.

Sichuan Basin

In February 2001, we signed two memoranda of understanding with PetroChina. These memoranda gave us the exclusive right to negotiate production-sharing contracts for three land blocks in the Sichuan province. We agreed with PetroChina to carry out joint feasibility studies on the Zitongxi, Zitongdong and Yudong blocks. These blocks, located in the Sichuan Basin, approximately 930 miles southwest of Beijing cover an area of approximately 2.2 million acres. PetroChina has drilled 39 wells on the three blocks, with twenty-six of these wells having been classified as producing gas wells. PetroChina has production tested 8 of the estimated 38 hydrocarbon bearing structures located on the three blocks. In September 2002, we signed a production-sharing contract (the Zitong Contract), with PetroChina covering both the Zitongxi and Zitongdong blocks. The contract received final Chinese regulatory approval in November 2002.

Under the Zitong Contract, Sunwing has 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, Sunwing must complete a minimum work program consisting of reprocessing 2,000 kilometers of seismic data, completing 500 additional kilometers of new seismic lines and drilling and completing two wells totaling at least 7,000 meters with estimated minimum expenditures of at least $18 million. Upon completion of the first phase, Sunwing must relinquish up to 30% of the Zitong block.

During phase two, Sunwing must complete a minimum work program consisting of new seismic lines totaling 350 kilometers and drill and complete two additional wells totaling 7,000 meters and incur minimum expenditures of at least $16 million. Following the completion of phase two, Sunwing must relinquish all of the property except any areas identified for development and production.

Sunwing can elect to commence the development of commercially viable deposits at any time following the submission of an ODP. Once Sunwing completes phase one of the exploration project, Sunwing can also elect not to proceed with phase two of the exploration project. However, once Sunwing commences a phase of the exploration project it must complete the minimum work program or else it will be obligated to pay, to PetroChina, the cash equivalent of the deficiency in the work program for that exploration phase.

If Sunwing identifies a hydrocarbon deposit for development and/or production, the parties will divide the participating interest in the project, with PetroChina entitled to fund and take up to 51% of the participating interest and Sunwing funding and taking the balance of the participating interest.

Once commercial production commences, Sunwing 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, Sunwing is entitled to production equaling its participating interest, subject to certain additional rights of the Chinese government. Assuming Sunwing holds a 49% participating interest, Sunwing will be entitled to approximately 75% of production initially, declining to approximately 45% after full exploration and development cost recovery.

PetroChina retains the rights to production from six existing wells located on the Zitong Block. Sunwing can drill new wells on the same formation as those tapped by the existing wells, but Sunwing s wells must be no closer than 1,000 meters from the existing wells.

In the first quarter of 2003, we established an office in Chengdu, the capital of Sichuan. We also completed our feasibility study obligations for the Yudong block and submitted a report to PetroChina in April 2002. In September 2002, we submitted a letter of intent to negotiate a production-sharing contract and our work plan for the Yudong block, and are currently awaiting PetroChina s reply.

CITIC Alliance

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

Under the terms of the agreement, CITIC will assist Sunwing in raising its profile in Asian capital markets and gaining access to future financing opportunities. CITIC will also support Sunwing in its plan to obtain a listing for its shares on the Stock Exchange of Hong Kong.

Sunwing will assist CITIC in identifying and acquiring interests in international oil and gas development projects and in introducing GTL and other advanced energy-sector technologies to China s domestic oil and gas industry. We hold a master license to Syntroleum s proprietary GTL process, but the geographical scope of our license does not currently include China.

CITIC has also agreed to assist Sunwing in its efforts to negotiate a production-sharing contract with PetroChina covering the Yudong block in Sichuan Province. Should a production-sharing contract for the Yudong block be obtained, Sunwing and CITIC will jointly participate in the development of the project on a 70/30 basis. Within 180 days thereafter, either party can elect to convert CITIC s 30% participating interest in the project into a 20% equity interest in Sunwing. CITIC has the right to appoint a representative to Sunwing s board of directors and will be entitled to appoint a second representative if, as and when it acquires a 20% equity interest in Sunwing.

RISK FACTORS

We are subject to a number of risks due to the nature of the industry in which we operate, 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 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 medium and long-term business plans, necessitating further growth and funding for implementation. We may be unable to achieve the needed growth to obtain profitability and may fail to obtain the funding that we need when it is required.

We are not able to guarantee the successful commercial development of our licensed gas-to-liquids technology.

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

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

We are in advanced negotiations with state-owned QP for a development and production-sharing contract, which is to form the basis for a large GTL project in Qatar. We can give no assurances as to when or if we will be able to conclude such a contract with QP. We are also exploring GTL project opportunities in Egypt and Oman, for which no conclusion has been reached.

Conflict in the Middle East may hamper our GTL project objectives

A conflict involving Iraq could harm our business in the short to medium term by making it difficult or impossible to continue our pursuit of GTL projects in Qatar and other countries in the Middle East or to obtain financing for projects we do succeed in obtaining. It is impossible to predict if or when a military conflict involving Iraq will occur, how long it will last if it does occur, the economic consequences of the conflict for the energy industry, regionally and globally, and how our business might be affected over the longer term.

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. 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.

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

In addition to our interest in our China projects, we may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, 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 western 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.

We may not be successful in negotiating additional production sharing contracts in China.

We hold our interests in China through two production-sharing contracts with CNPC for the Dagang and Zitong blocks. We also have a memorandum of understanding with PetroChina indicating a mutual intention to negotiate an additional production-sharing contract in the Sichuan basin. We cannot assure you, based on our existing memorandum of understanding with PetroChina, that we will successfully negotiate additional production-sharing contracts. It is possible that disputes between us could arise in the future, which must be resolved under foreign law. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

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 assessments and are 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 recognize 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 commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs or be sufficient to sustain our business.

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 project, 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, 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.

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 future net cash flows expected from them prepared by different independent engineers, or by the same engineers at different times may vary substantially.

Information in this document regarding our future exploitation projects 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.

Our business may be harmed if we are not able 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 holder of the license or lease, 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 not able 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. The laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities 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, for which we are a responsible person.

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

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

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

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

Our share ownership is highly concentrated and, as a result, our principal shareholders control our business.

Our directors and executive officers, including Robert M. Friedland, collectively own or have rights to acquire approximately 36% of our common stock and control our Board of Directors and determine 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 stock.

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. 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.

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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. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See Risk Factors.

ENVIRONMENTAL REGULATIONS

Both our oil and gas and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. We believe that our operations comply in all material respects with applicable environmental laws.

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

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.

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.

EMPLOYEES

At March 3, 2003, we had 73 employees. None of our employees are unionized.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities included under Item 8 in this Annual Report for information with respect to our oil and gas producing activities. We have not filed with or 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. In China for 2000, proceeds from the sale of oil produced were credited to our China cost center due to the stage of development of our projects in China. The average sales price realized on China production in 2000 was $28.26 per bbl. Average operating costs include lifting costs and production taxes, but exclude allocated head office engineering support costs, depreciation, depletion and amortization, royalties, income taxes, interest, selling and administrative expenses.

	Average Sales Price			Average Operating Costs		
	2002	2001	2000	2002	2001	2000
Crude Oil and Natural Gas ($/Boe)						
U.S.	$22.43	$21.93	$27.52	$6.76	$ 7.28	$10.00
China	$22.30	$24.42		$6.49	$10.50	

The following tables set 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:

	2002		2001		2000	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
U.S.	60(3)	43.9(3)	59	48.4	29	25.6
China	9(4)	7.4(4)	13	10.8	9	6.7

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

(3) After the sale of 4.4 net (7 gross) Spraberry wells in August 2002 and a 50% working interest, or 6.9 net wells, in our remaining Spraberry wells in October 2002.

(4) After the sale of 3.4 net (4 gross) Daqing wells in January 2002.

The following table sets forth, for each of the last three fiscal years, our participation in the completed drilling of net crude oil and natural gas wells:

Exploratory

	Productive		
	2002	2001	2000
U.S.			
China			
Total	0	0	0

	Dry		
	2002	2001	2000
U.S.	1.7(1)	1.5	2.5
China			
Total	1.7	1.5	2.5

At the end of 2002 and 2001 we had 2.3 (5 gross) and 3.3 (7 gross) net exploratory wells, respectively, which were either in the process of drilling or suspended.

(1) Includes 1.5 net exploratory wells (3 gross) drilled in Kentucky during 2001, which were determined to be dry in 2002.

Development

	Productive		
	2002	2001	2000
U.S.	8.8	22.8	25.6
China			3.3
Total	8.8	22.8	28.9

	Dry		
	2002	2001	2000
U.S.			2
China			
Total	0	0	2

The following tables set forth our holdings of developed and undeveloped oil and gas acreage at March 3, 2003:

	Developed		Undeveloped	
	Gross Acres(1)	Net Acres(2)	Gross Acres(1)	Net Acres(2)
U.S.	8,543	3,879	132,317	77,053
China(3)	1,729	1,418	900,320	896,607

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

(3) The number of developed acres disclosed in respect of our China projects relates only to those portions of the relevant fields covered by our pilot testing operations and does not include the remaining portions of the fields 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, 2002. Estimates for our China operations were prepared by independent petroleum consultants Gilbert Laustsen Jung Associates Ltd. Independent petroleum consultants Allan Spivak Engineering and Joe C. Neal & Associates prepared estimates for our U.S. operations.

	Our Share		Our Share of Before Tax Cash Flows in Thousands of Dollars Discounted at:			Our Share of After Tax Cash Flows in Thousands of Dollars Discounted at:		
	OIL	GAS						
	(MBbl)	(MMcf)	0%	10%	15%	0%	10%	15%
Net Proved Reserves(1)								
U.S.	1,784	819	$ 31,172	$ 21,485	$18,746	$ 31,172	$21,485	$18,746
China	15,604		196,861	84,692	56,796	144,205	59,782	41,369
	17,388	819	$228,033	$106,177	$75,542	$175,377	$81,267	$60,115

(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.

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

No matter was submitted to a vote of security holders during the fourth quarter of 2002.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares traded on the NASDAQ National Market and SmallCap Market during 2001 and 2002. As a result of our shares closing below $1.00 per share for 30 consecutive trading days during 2002 our shares were transferred from the NASDAQ National Market to the NASDAQ SmallCap Market on December 27, 2002. Currently our shares are traded on the NASDAQ SmallCap Market and The Toronto Stock Exchange.

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

NASDAQ MARKET (IVAN)

(US$)

	2002				2001			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q

High	.65	1.07	2.02	2.23	2.51	3.83	4.98	5.19
Low	.53	.85	1.72	1.93	1.40	1.39	3.18	3.25

THE TORONTO STOCK EXCHANGE (IE)

(CDN$)

	2002				2001			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	3rd Q	4th Q
High	1.01	1.74	3.12	3.50	3.99	5.80	7.40	7.65
Low	.88	1.45	2.83	3.11	2.20	2.15	4.90	5.15

On March 3, 2003, the closing prices for our common shares were $.57 on the NASDAQ SmallCap Market and Cdn. $.85 on The Toronto Stock Exchange.

Holders of Common Shares

As at March 3, 2003, a total of 144,465,818 of our common shares were issued and outstanding and held by 117 holders of record.

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 would after payment of the dividend 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.

Securities Authorized for Issuance Under Equity Compensation Plans

Our shareholders approved our Employees and Directors Equity Incentive Plan (the Plan). The Plan is intended to further align our directors and management s interests with the company s long-term performance and the long-term interests of our shareholders. Our shareholders also approved all amendments increasing the number of common shares available for issuance under the Plan. The following is as of March 3, 2003:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by shareholders	10,957,415	$ 2.60	666,998
Equity compensation plans not approved by shareholders	1,350,000	$ 0.77	0
Total	12,307,415		666,998

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 2003 is Cdn.$223 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

None

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report. 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 immediately noted 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 periods indicated:

	Year Ended December 31,				
	2002	**2001**	**2000**	**1999**	**1998**
	(stated in thousands of U.S. dollars, except per share amounts)				
Revenues	8,437	9,722	14,063	6,210	12,752
Total assets	107,088	104,003	99,800	47,659	49,442
Long-term debt	Nil	Nil	Nil	Nil	1,763
Net earnings (loss)	(6,819)(1)	(21,122)(1)	5,429	(7,802)(2)	(70,677)(3)
Net earnings (loss) per share basic	(0.05)	(0.16)	0.05	(0.08)	(0.79)
Net earnings (loss) per share diluted	(0.05)	(0.16)	0.04	(0.08)	(0.79)

(1) Includes asset write-downs of $2.4 million and $14.0 million for 2002 and 2001, respectively. See Notes 4 and 11 to our financial statements under Item 8 in this Annual Report.

(2) Includes asset write down of $2.5 million. See Note 8 to our financial statements under Item 8 in our 2001 Annual Report.

(3) Includes asset write down of $70.2 million. See Note 9 to our financial statements under Item 8 in our 2000 Annual Report.

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, is that an increase in ascribed value of shares issued for royalty interests in 2000 and 1999 of $1.4 million, additional impairment provision of $10.0 million in 2001 for our China properties and a write-off of $1.5 million and $5.1 million, in 2002 and 2001 respectively, in connection with development costs for our GTL prospects is required under U.S. GAAP. Determination of earnings per share in 2000, 1999 and 1998 is calculated excluding shares held in escrow. For U.S. GAAP reconciliation, see Note 19 to our financial statements.

Had we followed U.S. GAAP, certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows. Potential exercise of the stock options and warrants disclosed in Note 7 to the financial statements and potential conversion of the debt, Note 6, do not have a material dilutive effect on the earnings per share.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(stated in thousands of U.S. dollars, except per share amounts)				
Total Assets	91,921	90,219	101,158	48,852	49,442
Net earnings (loss)	(8,202)	(36,264)	5,429	(7,802)	(70,677)
Net earnings (loss) per share basic	(0.06)	(0.28)	0.05	(0.09)	(1.10)
Net earnings (loss) per share diluted	((0.06)	(0.28)	0.05	(0.09)	(1.10)

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

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements in Item 8. 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 2 and Note 19 to Notes to the Consolidated Financial Statements. For U.S. readers we have detailed the differences and have also provided a reconciliation of the differences between U.S. and Canadian GAAP in Note 19 to Notes 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 the full cost method of accounting for our oil and gas operations (as more fully described in Note 2 to the Consolidated Financial Statements), as compared to the other generally accepted method, successful efforts. Under the full cost method, costs associated with geological and geophysical activities and drilling successful and unsuccessful wells are capitalized on a country-by-country cost center basis. As a consequence, we may be more exposed to potential impairments if the book value of capitalized costs exceeds their future expected cash flows. This may occur if recoverable reserve estimates decrease, commodity prices decline or future estimates for capital, operating and income taxes increase, to levels that would significantly affect anticipated future cash flows.

Oil and Gas Reserves The process of estimating quantities of proved reserves is inherently uncertain and the reserve estimates included in this document are only estimates (see Risk Factors). You should not assume that the present value of our future cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with GAAP, we base the estimated future net cash flows from proved reserves on prices and costs on the date of estimate. Actual future prices and costs may be materially higher or lower than the prices and costs at the date of estimate.

Depletion Our rate of recording depletion is dependent upon our estimate of proved reserves and our assessment of unevaluated properties. If the estimates of proved reserves decline or our depletion cost base increases as a result of our assessment of impairment to our unevaluated properties, the rate at which we record our depletion expense increases, reducing net income. A decline in proved reserves may occur from lower product prices, which may make it uneconomic to drill for and produce higher cost fields.

Year Ended December 31, 2002

Overview

The year 2002 was a mixture of positive and negative results for Ivanhoe. On the downside we have, thus far, been disappointed with the exploration results from our drilling programs in the Bossier Trend, Northwest Lost Hills and Kentucky. Of the three wells drilled in the Bossier

Trend only one well is producing minimal levels of gas from the Bossier and the other two wells are suspended pending Unocal s assessment of the data and its plans for the prospects. In 2003, we plan to seek other partners who are willing to participate with us in testing promising zones uphole from the Bossier as well as other prospects in the Bossier sands. Although Northwest Lost Hills #1-22 well encountered natural gas in the Temblor formation, we have thus far been unable to complete negotiations with a potential partner to finance and participate in the testing of the Northwest Lost Hills #1-22 deep-gas well. We will either suspend or plug and abandon Northwest Lost Hills #1-22 pending final concurrence with Aera. Discussions and analysis are underway with Aera related to cost overruns on Northwest Lost Hills #1-22. We drilled three exploratory wells in Kentucky in 2001, none of which were successful in finding commercial quantities of gas. In 2002, we decided to relinquish our interests in the Kentucky prospects.

We continue to be pleased with our operations in South Midway from the 25% increase in production as a result of our cyclic steam program and the 40% increase in reserve quantities largely due to our success in proving up additional reserves in the southern expansion area. Oil and gas prices were in an upward trend throughout 2002 reducing the negative impact on revenues, which would have otherwise resulted from the sale of our reserves in Daqing and Spraberry during the year. More importantly our net revenues from operations were unchanged from 2001 largely due to our ability to reduce operating costs despite additional costs incurred for the cyclic steam operations in South Midway.

We were also able to achieve a 36% reduction in our project identification and administrative costs in 2002 as compared to last year through various cost reduction programs, including, scaling back our programs to identify new exploration projects and reduction in staff levels.

We concluded a production-sharing contract during 2002 with PetroChina in the Sichuan Basin that included both the Zitongxi and Zitongdong blocks located in China s largest gas producing region. Several gas-producing structures have already been discovered on these blocks. There is a strong and growing market for natural gas, with approximately 120 million people living within the Sichuan basin, an existing transportation grid within the Zitong block that is connected to many industrial and populated areas and one major trunk line is being built to ship gas to other new users in Eastern China. The alliance we concluded with CITIC during the year is a key step in potentially accessing the Asian capital markets to fund our China exploration and development programs.

Our negotiations for a GTL project in Qatar continue to move forward in a positive direction and we are at advanced stages in our negotiations. In December 2002, we formed GTLJ, a wholly owned Japanese subsidiary. We believe Japanese companies have the capacity to play multiple roles in investing, financing, engineering, marketing and consuming clean GTL products throughout the Far East. GTLJ is a vehicle through which Japanese companies may participate in a world-class GTL project in a number of these capacities.

Operations

Our net loss for the year was $6.8 million ($0.05 per share) compared to a net loss in 2001 of $21.1 million ($0.16 per share). The net decrease of $14.3 million is primarily due to an $11.6 million decrease in write down of properties from year-to-year and $3.2 million reduction in project identification and general and administrative costs. Our cash flow deficiency from operating activities for the year ended December 31, 2002 was $2.8 million, down from the cash flow from operating activities of $2.4 million we experienced in 2001. In 2002, we raised $10.1 million through private placements and the exercise of warrants and incentive stock options ($18.2 million was raised in 2001 from similar sources). In 2002, we received $0.5 million of financing from a related party (See Note 5 to the Consolidated Financial Statements, included in Item 8 herein). We invested $18.8 million in exploration, development and GTL activities in 2002, down from $40.5 million expended in 2001. Additionally, in 2002 we generated $5.4 million in cash from the sale of non-core assets in China and Texas.

Production

Revenues in the U.S. were flat for 2002 as a production decline of 2% from 2001 was offset by a 2% increase in the price per Boe. At South Midway, production increased 25% as a result of our cyclic steam program and the drilling of 7 additional oil wells in 2002. This was offset by a 28% decrease in Spraberry and Apache Flats production from 2001 levels due to natural declines, downtime as a result of workovers and the sale of our interests in certain wells.

At our South Midway field we have drilled 41 wells, 35 of which are producing oil. We are currently producing approximately 490 net Bbls/d compared to 400 net Bbls/d at the end of 2001. In 2002, we continued our cyclic steam enhancement project, which was very successful in increasing production rates ranging from 2.5 to 4 times. To date, we have cycle steamed 26 wells with one cycle and 3 wells with a second cycle. Our plan is to double our ultimate recoverable reserves through this program. We own a 100% working interest and a 93% net revenue interest in the project.

To date, we have drilled 32 wells in our Spraberry field. All 32 wells have been completed in one or more of the Wolfcamp and Spraberry zones. During the last half of 2002 we sold our interest in 7 Spraberry wells and 50% interest in 20 Spraberry wells. We have a 40% working interest, before payout, in 5 Apache Flats wells. Spraberry is producing approximately 120 net Boe/d compared to 300 net Boe/d at the end of 2001.

Revenues in China were down $0.8 million for 2002 due to a 9% decrease in oil prices from 2001 plus a 13% decrease in production from 2001 due to the sale of our Daqing project in January 2002 and a decrease in production at Dagang due to natural production declines and the shutting in of one well due to low production. The production decreases were partially offset by regaining a 20% interest in the Dagang field from Nippon Oil in mid-2001 and placing a reworked well on production late in 2002.

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We continue to produce pilot phase oil from 8 wells within our Dagang project at a 2002 year-end rate of 467 net Bbls/d, compared to 432 net Bbls/d at year-end 2001. During the fourth quarter 2002, we performed a workover on a well previously drilled by CNPC. Initial production after the workover commenced at 78 net Bbls/d and the well is currently producing at that same rate. In January 2002, we sold our interest in the Daqing project, which at year-end 2001 was producing 50 Bbls/d gross from 2 wells.

Operating costs, including engineering support, were $3.8 million for 2002 or $10.33 per Boe, compared to $4.8 million in 2001, or $11.95 per Boe. On our U.S. properties, the reduction per Boe results primarily from the installation of permanent production and electrical facilities in 2001 at South Midway as well as a reduction in operating costs at the Spraberry field as the wells mature. This is partially offset by an increase in costs incurred for cyclic steam activities, including engineering support. In China, we also installed permanent electrical facilities on certain wells in our Dagang project, reducing overall costs per Boe and we experienced improved operating efficiency at Dagang.

U.S. depletion costs per barrel for 2002 have increased 3% from 2001 primarily due to the reduction in our reserves as a result of the partial sale of our interests in Spraberry and an increase in our full cost center as a result of the impairment of properties. This increase is partially offset by the $14.0 million write off of depletable costs in 2001. The depletion costs in China have increased 22% or $1.51 per Boe compared to 2001, primarily as a result of anticipated increases in Dagang future development costs and the sale of our reserves at Daqing.

Since production revenues we generated during 2000 from China were credited to project carrying costs and production operations in the U.S. did not commence until late third quarter of 2000, 2000 is not comparable to 2002 and 2001 and is not presented below:

	2002			2001		
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production						
Boe	227,301	144,848	372,149	232,584	165,599	398,183
Boe/day for the year	623	397	1,020	637	454	1,091
Per Boe						
Oil and gas revenue	$ 22.43	$ 22.30	$ 22.38	$ 21.93	$ 24.42	$ 22.96
Operating costs	6.76	6.49	6.66	7.28	10.50	8.62
Production taxes	1.21		0.74	1.01		0.59
Engineering Support	2.38	3.80	2.93	2.12	3.62	2.74
	10.35	10.29	10.33	10.41	14.12	11.95
Net revenue before depletion	12.08	12.01	12.05	11.52	10.30	11.01
Depletion	8.39	8.30	8.35	8.12	6.79	7.56
Net revenue after depletion	$ 3.69	$ 3.71	$ 3.70	$ 3.40	$ 3.51	$ 3.45

Total revenues from our oil and gas operations were $8.3 million, $9.1 million and $0.9 million for 2002, 2001 and 2000, respectively.

General and Administration and Project Identification Costs

We continue to follow the practice of expensing the costs we incur in pursuing and investigating new projects, as well as costs associated with investment banking advice. In 2002, we incurred $5.7 million of general and administrative and project identification costs, down from $8.8 million in 2001. This decrease is directly attributable to our reduction in activities related to finding and investigating new projects, including $1.4 million of investment banking services incurred in 2001. In addition, in the third quarter of 2002, we implemented a cost reduction program that continues into 2003.

Interest Income

Interest income represents income we earned on our excess cash balances held during the year. Due to decreased cash balances and a decline in interest rate yields in 2002, interest income decreased $0.5 million from 2001.

Income Taxes

We have significant tax losses available to carry forward and reduce taxes otherwise payable. Details of these losses are in Note 13 to the consolidated financial statements included herein under Item 8. Given the uncertainty as to the utilization of these tax loss carry-forwards, we have followed the practice of recording a provision against the tax benefit asset resulting from these losses.

Exploration and Development Activities

Expenditures in 2002 on these activities were $16.9 million, down from $36.6 million in 2001. Capital spending in the U.S. was down $16.7 million in 2002, primarily due to a reduction in development drilling in Spraberry and South Midway, the completion of our Magic Mountain and Kentucky drilling programs in 2001, and the completion of our significant acreage acquisition program in the Bossier Trend at year-end 2001. These decreases were partially offset by an increase in drilling costs on Northwest Lost Hills #1-22. Spending in China was down $2.9 million to $3.6 million in 2002, primarily as a result of the pilot test in our Dagang project being completed in February 2001 and the sale of Daqing project in 2002, partially offset by an increase in spending on the Sichuan project in 2002.

At South Midway, we drilled 8 more development wells, 7 commercial oil producers and 1 gas supply well during 2002. (See above discussion under Production). Additionally, after initiating a pilot cyclic steam project in 2001, we commenced a full-scale steam project to enhance production. We anticipate drilling another 20 new wells in 2003 as we develop new reservoirs south of the main A and B areas of the project. See discussion below under Liquidity and Capital Resources.

In Texas, we drilled 2 more development wells in the Apache Flats area of our west Texas Spraberry project, both commercial producers. We sold our interest in certain wells within the Spraberry project, keeping our 40% interest in all of the wells in the Apache Flats area. (See above discussion under Production). In the Texas Bossier Trend, we completed 2 wells in the Cresslan Ranch prospect and one in the Lone Star prospect. One well is producing minimal levels of gas from the Bossier and the other wells are suspended pending Unocal s assessment of the data and its plans for the Bossier prospects. There are additional zones of interest above the Bossier sands waiting on testing. Currently Unocal has spent $8.3 million of the $10.1 million needed to earn a 50% interest in our holdings in Bossier.

At Lost Hills in California, the Northwest Lost Hills #1-22 well was successfully drilled to a measured depth of 21,000 feet and a liner set to 19,620 feet. While drilling the well, we encountered several high-pressure intervals which indicated the presence of natural gas. Testing operations have been suspended while we seek a partner to share the costs of the testing program. Accordingly, the commercial success of this well has not yet been determined.

Upon completion of our analysis of the data from the three Kentucky wells drilled in 2001 we decided not to perform further tests on any of the wells and to relinquish our interests.

During 2002, we signed a single production-sharing contract with PetroChina that includes two blocks in the Sichuan province of China. The contract was given final Chinese regulatory approval in November 2002, with a December 1, 2002 implementation date. The contract consists of two, three-year exploration periods, the first of which will include reprocessing of 2D seismic, the acquisition of new seismic and the drilling of 2 exploratory wells, the first of which must be spudded no later than September 2004. We also completed our feasibility study for the Yudong block within the Sichuan province, submitted the report to PetroChina and submitted a letter of intent to negotiate a contract and a work plan for Yudong. We currently await PetroChina s reply.

At our Dagang project in China, we submitted a final draft of our Overall Development Program to Chinese regulatory authorities for approval. We expect to receive final Government approval during the first half of 2003, after which the development phase will commence. We continue to operate the pilot wells with 82% of production revenue accruing to us.

Total capital spending on oil and gas operations, excluding non-cash transactions, for 2002, 2001 and 2000 was as follows:

	2002	2001	2000
Capital Expenditures:			
U.S	$13,306	$30,047	$21,899
China	3,626	6,568	5,676
	$16,932	$36,615	$27,575
Comprised of:			
Property acquisition	$ 913	$ 4,788	$ 6,392
Royalty rights		1,191	240
Seismic	30	1,348	3,840

Exploration	10,811	10,197	667
Development	5,178	19,091	19,376
Less: China oil production			(2,940)(1)
	$16,932	$36,615	$27,575

(1) Prior to proceeding to the development phase, oil revenue was credited to the China cost center.

Gas-to-Liquids (GTL)

GTL expenditures were $1.9 million for 2002, $3.9 million for 2001 and $13.2 million for 2000. The decrease in 2002 results from the 2002 completion of technical and commercial feasibility studies for both the Qatar and Egypt projects. In 2000, we acquired a master license from Syntroleum for $10.0 million and invested $2.0 million in Syntroleum s Sweetwater project in Australia.

Negotiations in Qatar for an agreement to build GTL and natural gas liquids (NGL) plants continue and are currently at an advanced and detailed stage. The GTL project that we are negotiating will include the development of natural gas reserves in Qatar s huge offshore North Field; the construction of an NGL plant to produce 80,000 Bbls/ d of condensate, 24,000 Bbls/ d of propane and 17,000 Bbls/ d of butane; and the construction of a modular GTL plant to produce 185,000 Bbls/d of ultra-clean naphtha and diesel fuel. The total cost of the project will be approximately $5 billion. We can offer no assurances that our negotiations will ultimately lead to an agreement for a GTL project.

We continue to work with Japanese companies to optimize the commercial structure for utilization of GTL and NGL products produced in our planned Qatar project. Additionally, testing of the GTL diesel has been completed by various Japanese automotive interests in an effort to gain acceptance of GTL fuel in that marketplace. A market analysis for the Asia/ Pacific region, Western and Eastern Europe and U.S. markets has been completed. Development of a project financing plan, utilizing Japanese and global resources, is continuing.

Based on our ongoing commercialization studies and the growing demand for cleaner sources of energy in Japan, we have incorporated a new subsidiary in Japan to facilitate the potential future participation by Japanese companies in the Qatar GTL project. If, as and when we obtain the right to develop this project, we intend to assign up to 5% of our interest to GTLJ, our new Japanese subsidiary. GTLJ would then invite Japanese companies from the refining and distribution, exploration and production, trading and manufacturing industry sectors to invest in GTLJ on certain commercial terms. Any proceeds raised would be used to fund up to an estimated $250 million of project costs including front-end engineering and design. Additional sources of financing for this predevelopment work are being pursued to obtain the most competitive and favorable terms.

In Egypt, we are currently studying alternative scenarios that could improve economics for a 45,000 Bbls/ d GTL plant. Continued discussions have resulted in the Ministry of Petroleum s willingness to consider alternative configurations to the plant design. In Oman, we made preliminary proposals for plant sizes ranging from 45,000 90,000Bbls/ d. The Ministry of Oil and Gas has been studying our proposals.

In June 2002, we signed a letter of intent with Syntroleum to participate in the Syntroleum U.S. Department of Energy Fuels Project at a cost of $5.0 million. Participation is contingent upon our finalizing and signing the GTL agreement in Qatar. The goal of the project is to establish GTL diesel production from a demonstration plant in such volumes so as to supply adequate quantities to various GTL fuel field trials. Participation allows us sufficient supplies of GTL, diesel and naphtha to provide samples to potential buyers. Additionally, we will have access to the demonstration plant for the purpose of gaining operational experience and training future operations personnel. The project cost is to be offset by $2.0 million of our investment in Syntroleum s Sweetwater project in Australia, which was cancelled by Syntroleum.

Liquidity and Capital Resources

Our capital expenditure budget for 2003 is $18.5 million; $5.0 million is required to develop the southern expansion in South Midway and $10.0 million to develop the Dagang field. The Dagang development program is scheduled to begin after receiving final approval from the Central Government by mid-2003. The plan is to fund both capital programs with debt and or equity financing. In February 2003, we arranged financing for the South Midway expansion development. The 2003 budget for the Sichuan seismic acquisition program is $3.5 million. Our plan is to fund Sichuan from existing cash balances, cash flows from operations, further sales of non-core assets and loans from related parties. Further equity financings will also be considered as a source of funds should capital markets become more favorable.

We view the Sunwing and CITIC strategic alliance as a key step in potentially accessing the Asian capital markets to fund our China exploration and development programs. Our objective in forming the alliance is to raise Sunwing s profile and enhance its credibility among Asian institutional investors with a view to a possible listing of Sunwing s shares on the Stock Exchange of Hong Kong.

We undertook measures during the third quarter of 2002 to better position ourselves for 2003 when we believe one or more of our major upside potential projects will materialize and access to capital markets will become more accommodating. This included employee and overhead cost reductions, sale of non-core wells in the Spraberry field and the hedging of crude oil prices for a portion of our U.S. production. Additionally, we are optimistic that our cyclic steam program in South Midway will continue to generate good cash

flow levels and that these results will be further enhanced by our plans to drill another 20 wells in the coming year. We will continue to pursue sales of non-core assets and pursue joint venture partners to implement our capital programs when opportunities arise.

After March 27, 2003, the $1.0 million unsecured, convertible debenture will be payable 90 days following written demand by the lender, assuming it is not converted into our common shares prior to March 27, 2003. Our plans are to negotiate an extension of the conversion period for up to an additional 180 days under the current terms. Should demand for payment be made, our plan is to fund the payoff with equity financing or loans from related parties.

During 2002, we raised $10.1 million through the issuance of common shares and $0.5 million through a related party loan agreement. Additional funding will be required to complete future capital programs through a combination of equity, debt and joint venture partner participation. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our capital programs. If we are unsuccessful, we will have to prioritize our capital programs, which may result in delaying and potentially losing some valuable business opportunities.

Off Balance Sheet Disclaimer:

At December 31, 2002 and 2001, 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.

Year Ended December 31, 2001

Overview

Our 2001 U.S. production increased almost 8 fold over 2000 to 232,600 Boe. Net revenues from our U.S. projects increased to $5.1 million from $0.9 million the previous year. Our 2001 China pilot production increased 61% to 165,600 barrels of oil with net revenue increasing $1.1 million to $4.0 million. Our operating results however, suffered from the decline in oil and gas prices in the second half of 2001. In the U.S. these declines necessitated a provision for impairment of capitalized costs of $14.0 million and reduced our net revenue to $1.1 million in the fourth quarter compared to $1.5 million in the previous quarter. In China, the fourth quarter decline in net revenue was less dramatic due to the impact of three month averaging of our oil prices. However, on application of U.S. GAAP at year-end an impairment provision of $10.0 million on the carrying value of our China properties was necessary

Operations

Our net loss for the year was $21.1 million ($0.16 per share) compared to net income in 2000 of $5.4 million ($0.05 per share). The net change year-over-year of $26.5 million is attributable to a $14.0 million write down of our U.S. properties under the ceiling test calculation in 2001 and the $12.2 million gain on the sale of our Russian properties recorded in 2000. As more fully explained in Note 19 to our consolidated financial statements, included in Item 8 herein, on application of U.S. GAAP an additional $10.0 million write down of our China property and a $5.1 million write-off of capitalized development costs in connection with our GTL prospects are required. No similar write-downs are required under Canadian GAAP. Our cash flow from operating activities for the year ended December 31, 2001 was $2.4 million, up from the cash flow deficiency from operating activities of $11.8 million we experienced in 2000. In 2001, we raised $18.2 million through private placements and the exercise of warrants and incentive stock options ($47.7 million was raised in 2000 from similar sources). In 2001, we invested $40.5 million ($40.8 million in 2000), primarily in exploration and development activities.

Production

At our South Midway field in California, we drilled 31 wells, 29 of which are producing. We produced approximately 400 net Bbls/ d. In the fourth quarter of 2001, we completed a pilot cyclic steam enhancement project, which more than doubled production rates in the five wells that were treated. We own a 100% working interest and a 93% net revenue interest in the project. Aera elected not to participate in this project but receives royalties pursuant to the Aera exploration agreement.

As of the end of 2001, we drilled 30 wells in the Spraberry field, which are producing approximately 300 net Boe/ d. All 30 wells have been completed in one or more of the Wolfcamp zones but 5 wells were awaiting their Spraberry zone completions. As of the end of 2001, we drilled three wells in the Apache Flats area that are producing 40 net Boe/ d.

South Midway and Spraberry are our only producing fields in the U.S. The substantial declines in oil and gas product prices during 2001 have had significant impact on our operating profitability at these fields and have made it necessary to provide a provision for impairment on the carrying value of our U.S. evaluated oil and gas assets. We recorded an impairment provision of $14.0 million in 2001.

General and Administration and Project Identification Costs

During 2001, we incurred $6.2 million, up $2.5 million from the $3.7 million incurred in 2000, in costs associated with international project opportunities that we have rejected. Of the increase, $1.4 million is attributable to payments to investment bankers for assistance with financial and strategic planning. We incurred other general and administrative costs of $2.6 million during 2001, down $0.3 million from the $2.9 million we incurred in 2000.

Other Income and Expenses

Interest income represents income we earned on our excess cash balances held during 2001. The decrease of approximately $0.4 million from 2000 arises from a reduction of our cash balances and interest rates during 2001. Russian litigation costs ceased in mid 2000 with the successful resolution of our dispute with our Russian joint venture partner and divestiture of our Russian projects. Depletion and depreciation is up $2.9 million from 2000 due to the inclusion of production from our U.S. properties for a full year and the inclusion of production from China in income in 2001.

Exploration and Development Activities

During 2001, we continued our exploration program in the San Joaquin Valley of Southern California on acreage primarily acquired under the Aera exploration agreement. We spud our first deep gas exploration well at Northwest Lost Hills in Kern County in August 2001. In addition, we drilled 2 other exploration wells in southern California, which were unsuccessful, and were abandoned. At South Midway we drilled 10 more development wells, all commercial oil producers. Additionally, we initiated a pilot cyclic steam enhancement project, resulting in a full-scale steam project, which commenced in 2002. We acquired overriding royalties, ranging from 1.8% to 6.6%, in the deep rights of certain leases of the Aera exploration agreement.

In Texas, we drilled an additional 14 producing wells during 2001 in the Spraberry Trend acreage in West Texas. In 2001, we spud 2 wells in the Creslenn Ranch prospect within the Bossier Trend in East Texas, both of which encountered gas shows. We continued to increase our leased acreage in the Bossier area during 2001.

At our Dagang Project in China, we completed our pilot-testing phase in February 2001 and later in the year submitted our overall development plan to the Chinese authorities for their approval, which is expected in the first half of 2003. At our Daqing Project, our overall development plan was approved in February 2001 and we resumed operatorship and rights to revenues on March 1, 2001. Our Daqing Project is small by international standards and negotiations with CNPC for additional blocks to be included in the contract area have proved unsuccessful and after an internal review of our China projects, and based on our shift towards major gas development in China we put the Daqing project up for disposal. Effective January 2002, we disposed of the project for $2.4 million in cash and an overriding royalty on future production.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 reserves.

We currently have limited production. Until June 1999, we had a successful producing project in Russia, but legal actions initiated in the Russian courts by our Russian joint venture partner deprived us of the right to operate the field and to realize any continuing return on our investment. As a result, we sold our interest in the project in August 2000. Oil and gas revenue reported before 2000 was generated from our share of production from the Russian project.

The Company s results of operations are sensitive mainly to fluctuations in oil and natural gas prices. We are currently engaged in derivatives to hedge the cash flow from a portion of our U.S. oil production. See Note 10 to the Consolidated Financial Statements in Item 8.

We are exposed to the risk that we may require a provision for impairment as to the carrying value of our oil and gas assets. Such value is compared quarterly to the estimated recoverable value of our proved reserves based on period-end commodity prices, unescalated. We are exposed to the risk that we will be unable to engage competent cost-effective contractors and suppliers for our operations, risks that damage to, or malfunction of, our equipment will hinder our ability to carry out our exploration activities and risks that foreign laws may not adequately protect our interests in disputes with foreign partners and others.

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In the international petroleum industry, most production is bought and sold in U.S. currency or with reference to U.S. currency. Accordingly, we do not expect to face foreign exchange risks if and when we commence large-scale commercial production. Most of our business transactions are conducted in U.S. currency in the countries in which we operate.

We currently have minimal debt obligations 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

AUDITORS REPORT

To the Shareholders of

Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2002 and 2001 and the consolidated statements of loss (income) and deficit and cash flow for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards, and United States generally accepted auditing standards. Those 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 the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta	(signed) Deloitte & Touche LLP
February 14, 2003	Chartered Accountants

COMMENTS BY AUDITORS FOR U.S. READERS ON

CANADA U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when the financial statements are affected by conditions and events that cast uncertainty as to the Company s ability to carry out and complete planned activities without raising additional financing, as described in Note 1 to the financial statements. Our report to the shareholders dated February 14, 2003 is expressed in accordance with Canadian reporting standards which do not permit a reference to such events and conditions in the auditors report when these are adequately disclosed in the financial statements.

In the United States, reporting standards for auditors also require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 7 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations Section 3870.

Calgary, Alberta	(signed) Deloitte & Touche LLP
February 14, 2003	Chartered Accountants

IVANHOE ENERGY INC.

Consolidated Balance Sheets

(stated in thousands of U.S. Dollars)

	As at December 31,	
	2002	**2001**
Assets		
Current Assets		
Cash	$ 3,980	$ 9,697
Accounts receivable *(Note 3)*	2,519	1,938
Other	691	375
	7,190	12,010
Long term assets	462	397
Oil and gas properties, equipment and GTL investments, net *(Note 4)*	99,436	91,596
	$ 107,088	$ 104,003
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 4,797	$ 5,974
Demand loan payable *(Note 5)*	500	
Convertible debentures *(Note 6)*	1,000	1,000
	6,297	6,974
Provision for site restoration	243	132
Shareholders Equity		
Share capital (Note 7)	131,112	120,392
Deficit	(30,564)	(23,495)
	100,548	96,897
	$ 107,088	$ 104,003

Approved by the Board:

(signed) David Martin
Director

(signed) E. Leon Daniel
Director

IVANHOE ENERGY INC.

Consolidated Statements of Loss (Income) and Deficit

(stated in thousands of U.S. Dollars, except per share data)

	Year Ended December 31,		
	2002	**2001**	**2000**
Revenue			
Oil and gas revenue	$ 8,329	$ 9,144	$ 851
Interest income	108	578	990
Gain on Russia projects *(Note 12)*			12,222
	8,437	9,722	14,063
Expenses			
Operating costs	3,841	4,758	787
Project identification costs	733	6,210	3,732
General and administrative	4,934	2,635	2,914
Russian litigation			860
Depletion and depreciation	3,312	3,241	341
Write offs and provision for impairment *(Notes 4 and 11)*	2,436	14,000	
	15,256	30,844	8,634
Net Loss (Income) ***(Note 13)***	6,819	21,122	(5,429)
Deficit, beginning of year	23,495	2,373	7,802
Loss on acquisition of shares *(Note 7)*	250		
Deficit, end of year	$ 30,564	$ 23,495	$ 2,373
Net Loss (Income) per Share ***(Note 14)***			
Basic	$ 0.05	$ 0.16	$ (0.05)
Diluted	$ 0.05	$ 0.16	$ (0.04)
Weighted Average Number of Shares (in thousands) ***(Note 14)***			
Basic	142,314	128,598	119,719
Diluted	142,314	128,598	124,549

IVANHOE ENERGY INC.

Consolidated Statements of Cash Flow

(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2002	**2001**	**2000**
Operating Activities			
Net (loss) income	$ (6,819)	$(21,122)	$ 5,429
Items not requiring use of cash			
Gain on Russian projects *(Note 12)*			(12,222)
Write offs and provision for impairment *(Notes 4 and 11)*	2,436	14,000	
Depletion and depreciation	3,312	3,241	341
Other			67
Changes in non-cash working capital items	(1,687)	6,314	(5,448)
	(2,758)	2,433	(11,833)
Investing Activities			
Capital spending	(18,828)	(40,504)	(40,827)
Proceeds from sale of assets *(Note 4)*	5,351		
Recovery from Russia projects			31,710
Other	(65)	(155)	292
	(13,542)	(40,659)	(8,825)
Financing Activities			
Shares issued on private placements (net)	9,964	17,903	38,598
Shares issued on exercise of options and warrants	119	326	9,117
Proceeds from demand loan *(Note 5)*	500		
	10,583	18,229	47,715
Increase (decrease) in cash and cash equivalents, for the year	(5,717)	(19,997)	27,057
Cash and cash equivalents, beginning of year	9,697	29,694	2,637
Cash and cash equivalents, end of year	$ 3,980	$ 9,697	$ 29,694
Supplementary Information			
Regarding Non-Cash Transactions			
Investing activities, net assets acquired *(Note 4)*			
Overriding royalties	$	$ 2,852	$ 917
Lease acquisition		$ 900	
Accounts receivable		200	
	$	$ 3,952	$ 917
Financing Activities, non-cash			
Shares issued as consideration	$	$ 3,952	$ 917
Included in the above are the following:			
Taxes paid or (refunded)	$ (27)	$ 104	$ 8

Interest paid	$ 74	$ 111	$ 120
Decrease (increase) in non-cash working capital items			
Accounts receivable	$ (581)	$ 2,794	$ (3,182)
Other current assets	(316)	497	(248)
Accounts payable and accrued liabilities	(790)	3,023	(2,018)
	$ (1,687)	$ 6,314	$ (5,448)

IVANHOE ENERGY INC.

Notes to the Consolidated Financial Statements

(all tabular mounts are expressed in thousands of U.S. Dollars, except per share data)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) the application of gas-to-liquids technology 2) enhanced oil recovery and 3) exploration and development of hydrocarbons. Operations are currently carried out in the U.S. and China.

The Company s activities contemplate significant capital expenditures to develop its properties and projects. Significant financing will need to be raised through equity, debt financing and joint venture partner participation in order to complete the planned activities. In the event that such financing is not available to the Company, it will be necessary to prioritize activities, which may result in delaying, and potentially losing, business opportunities and causing potential impairment to recorded assets.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The consolidated financial statements also conform in all material respects to U.S. GAAP, except for the following matters for which details are provided in Note 19: the price per share used to record the acquisition of royalty interests; reduction of the deficit as at December 31, 1998; net loss (income) for 2001 as a result of an additional ceiling test provision required under U.S. GAAP and the requirement to write-off capitalized development costs incurred in connection with our GTL prospects; net loss (income) per share calculations; and additional disclosures required under U.S. GAAP.

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.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned.

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 denominates it s business. Monetary assets and liabilities denominated in foreign currencies are converted 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 at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the translation of foreign currency amounts are reflected in 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, demand loan payable and convertible debenture, approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

Oil and Gas Properties

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 land acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both productive and non-productive wells, gathering and production facilities and equipment, and financing and administrative costs related to capital projects. Proceeds from sales of oil and gas properties are recorded as reductions of capitalized costs, 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.

Costs of oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit of production method based on estimated proved reserves. Significant development projects and expenditures on exploration properties are excluded from the depletion calculation until evaluated. These excluded costs are evaluated periodically for impairment.

Royalties acquired are included in oil and gas properties and recorded at cost.

Depletable costs, accumulated in each cost center, net of depletion provided, future income taxes and accumulated site restoration costs, are compared annually to the non-discounted estimated future net revenues from proved reserves (based on year-end non-escalated prices), net of estimated administration and carrying costs, and related production and income taxes (ceiling test). Any accumulated costs in excess of the calculated ceiling test are charged to operations as a provision for impairment.

Provision for Future Site Restoration

The Company has developed an estimate for future site restoration and abandonment costs and is amortizing this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision is included with depletion and depreciation expense.

Furniture and Fixtures

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.

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.

Loss (Income) Per Share

The loss (income) per share is computed on the basis of the weighted average number of shares outstanding during each year. Effective January 1, 2001, the Company adopted, retroactively, the treasury stock method to determine diluted earnings per share (Note 14).

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 Plan

The Company has an Employees and Directors Equity Incentive Plan consisting of stock option, bonus and share purchase incentives (Note 7). The Company accounts for its stock-based compensation plan using intrinsic-values. Compensation costs are not recognized in the financial statements for stock options granted to employees and directors when granted at market value. Compensation costs are, however, recognized in the financial statements for options granted to non-employees based on the fair value of the options at the date granted. Consideration paid upon exercise of stock options is credited to share capital.

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

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 revenue receivable balances and revenues from significant customers:

	Accounts Receivable as at December 31,		Oil and Gas Revenues for the Year Ended December 31,	
	2002	2001	2002	2001
U.S. Customers				
A	$ 346	$ 189	$2,916	$2,034
B	192	328	1,764	2,500
C	63	97	390	554
All Others		1	29	13
	601	615	5,099	5,101
China Customer				
A	767	562	3,230	4,043
	$1,368	$1,177	$8,329	$9,144

Included in accounts receivable as at December 31, 2002 and 2001 are $0.3 million and $0.5 million, respectively, of costs billed to joint venture partners and $0.8 million and $0.2 million, respectively, of advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES, EQUIPMENT AND GTL INVESTMENTS

Capital assets categorized by geographic location are as follows:

	December 31, 2002			December 31, 2001		
	U.S.	China	Total	U.S.	China	Total
Oil and gas properties and equipment	$ 76,323	$26,617	$102,940	$ 65,997	$25,427	$ 91,424
Accumulated depletion	(4,036)	(2,326)	(6,362)	(2,143)	(1,124)	(3,267)
Provision for impairment	(14,000)		(14,000)	(14,000)		(14,000)
	58,287	24,291	82,578	49,854	24,303	74,157
Gas to Liquids Investments						
Master license	10,000		10,000	10,000		10,000
Investment in Sweetwater partnership				2,000		2,000
Feasibility studies and other deferred costs	6,603		6,603	5,142		5,142
	16,603		16,603	17,142		17,142
Support equipment	457	36	493	467		467
Accumulated depreciation	(238)		(238)	(170)		(170)
	219	36	255	297		297
	$ 75,109	$24,327	$ 99,436	$ 67,293	$24,303	$ 91,596

During 2002, the Company sold working interests in the Spraberry field in west Texas for $3.0 million and the Daqing project in China for $2.4 million. The Company retains an overriding royalty in the Daqing project of 4% before cost recovery and 2% thereafter. The sale proceeds were credited to the respective full cost centers, (Note 2) as the sales do not represent significant dispositions of the U.S. and China total reserve bases.

Costs as at December 31, 2002 of $46.6 million (2001 $40.3 million; 2000 $24.8 million) related to unevaluated oil and gas properties are excluded from the depletable cost centers.

For the year ended December 31, 2002 general and administrative expenses related directly to acquisition, exploration, development and GTL activities of $2.6 million (2001 $3.6 million; 2000 $1.5 million) were capitalized.

Gas-to-Liquids

In 2000, the Company acquired a master license from Syntroleum Corporation permitting the Company to use their proprietary gas-to-liquid process (GTL) in an unlimited number of projects around the world except North America, China and India. In June 2002, the master license was amended, which would reschedule payment of a portion of upfront site license fees on specific milestone dates and the balance over the future revenues generated. The Syntroleum process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. The Company views the process as holding significant potential for monetizing stranded natural gas deposits around the world.

During 2002 and 2001, the Company has undertaken detailed project feasibility studies for the construction, operation and cost of world-class GTL plants in Qatar, Egypt and Oman. In addition, the Company conducted marketing, commercialization and transportation feasibility studies. Marketing studies were conducted for both Europe and the Asia-Pacific regions for GTL diesel and naphtha. Markets within these regions were identified and premiums for the GTL ultra clean fuels were estimated. Product forecasts from these studies were used to complete studies with various Japanese companies to optimize the commercial structure for utilization of GTL diesel and NGL products. All cost associated with these projects have been capitalized.

In June 2002, the Company signed a letter of intent with Syntroleum to participate in the Syntroleum U.S. Department of Energy (DOE) Fuels Project at a cost of $5.0 million. The DOE project cost is to be offset by $2.0 million of the Company s investment in Syntroleum s Sweetwater project in Australia, which Syntroleum cancelled. As Sweetwater is not proceeding and participation in the DOE project is contingent upon the Company successfully signing a GTL contract, which is not assured, the Company has written off its $2.4 million investment in the Sweetwater project.

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.

United States

In 1998, the Company acquired rights to an exploration agreement (Agreement) with Aera Energy LLC (Aera), which gave the Company access to all of Aera s exploration, seismic and technical data in southern San Joaquin Valley in California for the purpose of identifying drillable exploration prospects within the exclusive area. The Agreement provided the Company the right to a working interest ownership in all drillable prospects in which Aera elects to participate equal to a minimum of 12.5% and a maximum of 75%. In those prospects in which Aera elects not to participate, the Company has the right to proceed with a 100% working interest and to seek other joint venture partners. Aera has the right to act as the operator for any drillable prospects in which Area elects to participate.

The Company has identified 12 prospect Areas of Mutual Interest (AMI s) containing a total of 30 drillable prospects in which Aera has elected to participate under the Agreement. The Company s working interests, in these AMI s, range from 12.5% to 50%. The Company has a 100% working interest in 3 AMI s in which Aera has declined to participate. In participation with Aera, the Company has drilled 3 wells in the AMI s, 1 of which was unsuccessful and 2 have been suspended, including the Northwest Lost Hills #1-22 deep gas well. Additionally, the Company has drilled 35 producing wells in South Midway in which the Company has a 100% working interest.

The Company has drilled 27 producing wells in the Spraberry field and 5 producing wells in the Apache Flats field in West Texas with non-operating working interests of 62.5% and 96.15% in Spraberry and 40% in Apache Flats. In 2002, the Company sold its interests in 7 Spraberry wells for $1.4 million and 50% of its interests in the remaining 20 Spraberry wells for $1.6 million.

The Company drilled three unsuccessful wells in Kentucky and in 2002 decided to abandon the wells and relinquish its interests.

The Company has leased mineral rights in the Bossier Trend in east Texas and entered into joint venture agreements with a subsidiary of Unocal Corp. (Unocal) under which Unocal will earn a 50% interest in the Company s holdings by expending the next $10.1 million of costs associated with exploration and development of prospects. Unocal has drilled three wells in two prospects and has spent $8.3 million. One of the wells is producing small quantities of gas and the other two are suspended pending testing of upper zones.

China

The Company currently holds a production-sharing contract to develop existing oil properties in the Dagang region. The Company incurs 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery. The pilot phase at Dagang was completed in February 2001. Nippon Oil Exploration Limited of Japan (Nippon), earned a 20% working interest in the Company s interest in the project by funding a disproportionate share of the Dagang pilot testing expenditures. In August 2001, Nippon decided to withdraw from the project and their interest reverted back to the Company. The Company submitted the Overall Development Program to China National Petroleum Corporation in 2002 and approval of the development program is expected in the first half 2003. During the development program preparation and approval process the Company continues to operate the Dagang project.

Prior to 2002, the Company held a contract to develop existing oil fields in the Daqing region and the pilot program was completed successfully in 1998. In January 2002, the Company was successful in disposing of the project for $2.4 million and retains an overriding royalty on future production.

During the pilot testing phase at Dagang and Daqing all production costs and revenues were capitalized to oil and gas properties and equipment. With the evaluation stage completed and the decision to enter the development and implementation stage, all operating results beginning January 1, 2001 for Dagang and March 1, 2001 for Daqing are included in the Company s statements of loss (income) and deficit.

In September 2002, the Company signed a 30-year production-sharing contract with PetroChina Corporation (PetroChina) covering approximately 900,000 acres. The contract area, known as the Zitong block, is located in the northwestern portion of the Sichuan Basin, China s largest gas-producing region. Under the terms of the contract, the Company will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue before costs are recovered and approximately 45% thereafter. PetroChina has the option to participate in any successful developments, with up to a 51% working interest. The Company will conduct exploration activities over the block, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. In addition, pursuant to existing exclusive arrangements, the Company has the right to negotiate a production-sharing contract for the Yudong block located on the eastern edge of the Sichuan Basin.

Overriding Royalties

Through a series of transactions from 1999 to 2001, the Company acquired overriding royalties in the AMI prospects and other properties in California ranging from 1.46% to 6.58% in consideration for $0.9 million cash and the issuance of 2,885,000 common shares at an aggregate ascribed value of $8.0 million, being 1,562,000 common shares at $2.02; 523,000 common shares at $1.76 and 800,000 common shares at $4.94. Of the total consideration paid, $0.9 million was allocated to property acquisition costs and $0.2 million to accounts receivable.

5. DEMAND LOAN PAYABLE

In December 2002, the Company borrowed $0.5 million from a related party. The unsecured loan is due 90 days after written demand, on the closing date of obtaining equity financing or December 31, 2005 whichever occurs earliest. The loan bears interest at U.S. prime plus 3%.

6. CONVERTIBLE DEBENTURE

The $1.0 million unsecured convertible debenture was originally due within 90 days following written demand and was convertible (including principal and accrued interest) into common shares of the Company at Cdn. $2.75 per share until August 2002. In October 2002, the Company concluded an agreement in which the lender agreed not to demand repayment of the debenture until March 27, 2003. Principal and accrued interest will be convertible until March 27, 2003, at lender s option, into common shares of the Company at U.S.$0.77 per share. Thereafter, the debenture is due at any time within 90 days following written demand. The debenture bears interest at U.S. prime plus 2.5%.

7. 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.

The total number of issued and outstanding common shares is as follows:

	Number of Common Shares	Amount
	(thousands)	
Balance December 31, 1999	110,539	$ 49,494
Issued for private placements, net	11,250	38,598
Issued on exercise of warrants	2,998	8,083
Issued on exercise of options	1,545	1,034
Issued on acquisition of overriding royalties *(Note 4)*	523	917
Issued for services	19	85
Balance December 31, 2000	126,874	98,211
Issued for private placements, net	11,260	17,903
Issued on exercise of warrants	127	166
Issued on exercise of options	206	160
Issued on acquisition of overriding royalties *(Note 4)*	800	3,952
Balance December 31, 2001	139,267	120,392
Issued for private placements, net	5,000	9,964
Issued on exercise of options	163	119
Issued for deferred compensation	201	387
Elimination of employee loans		409
Retirement of shares	(165)	(159)
Balance December 31, 2002	144,466	$ 131,112

The Company loaned $0.4 million to an employee and two directors to facilitate their exercise of stock options and warrants to purchase 165,000 common shares of the Company. The Company held the shares as collateral for the loans. The loan balances were previously netted against the share capital balances. In December 2002, the Company determined the loans would not be renewed when they became due in December 2002 and January 2003. Each of the borrowers authorized the Company to acquire the shares held as collateral in full payment of their loan amounts and accrued interest, thereon. Subsequently, the Company eliminated the loans and retired the 165,000 common shares at the average price of all common shares then issued and outstanding ($0.96 per share) and recorded a $0.25 million loss to retained earnings.

Private Placements and Share Purchase Warrants

During 2000, the Company issued common shares under two private placements. In January and February 2000, the Company issued 6,250,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of $14.0 million. Each two warrants were exercisable into one common share at Cdn.$4.00 until the first anniversary date of the private placement. All of these warrants were exercised. On October 17, 2000, the Company issued 5,000,000 units, each unit consisting of one common share and one share purchase warrant, for net proceeds of $24.6 million. Each two warrants were exercisable into one common share at $5.38 until October 17, 2002. The warrants were not exercised and have been cancelled.

Under a private placement in October 2001, the Company issued 11,260,000 common shares at $1.60, for net proceeds of $17.9 million.

Under a private placement on March 2002, the Company issued 5,000,000 common shares at $2.00, for net proceeds of $10.0 million.

Equity Incentive Plan

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

Stock options are issued at not less than the quoted 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. Options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Options granted after March 1, 1999 vest over four years and expire five 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, 2002		December 31, 2001		December 31, 2000	
	Number of Shares	Weighted-Average Exercise Price	Number of Shares	Weighted-Average Exercise Price	Number of Shares	Weighted-Average Exercise Price
	(000 s)	(Cdn.$)	(000 s)	(Cdn.$)	(000 s)	(Cdn.$)
Outstanding at beginning of year	8,635	$2.66	8,161	$2.45	7,800	$1.18
Granted	2,095	$2.86	846	$4.63	1,991	$6.39
Exercised	(164)	$1.57	(206)	$1.40	(1,545)	$1.20
Cancelled/forfeited	(301)	$3.48	(166)	$4.04	(85)	$1.09
Outstanding at end of year	10,265	$2.69	8,635	$2.66	8,161	$2.45
Options exercisable at year end	7,122	$2.13	6,089	$1.73	5,356	$1.24

Effective January 2002, Canadian accounting standards require disclosure on a pro forma basis of the impact on net income of using the fair value method for stock options granted to employees and directors on or after that date. Had compensation expense been determined based on the fair value at the option grant date, the Company s net loss and net loss per share for the year ended December 31, 2002 would have been $7.1 million and $0.05 per share, respectively. The foregoing is calculated in accordance with Black-Scholes options pricing model, using the following data and assumptions: 72% price volatility, using the prior two years weekly average prices of the Company s common shares; expected dividend yield of 0%; option terms to expiry of 5 years, as defined by the option agreements; risk-free rate of return as of the date of the grant of 4.35% to 5.58%, based on one and five year Government of Canada Bond yields.

The following table summarizes information respecting stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable	Weighted-Average Exercise Price
(Cdn.$)	(000 s)	Yrs.	(Cdn.$)	(000 s)	(Cdn.$)
$0.50 to $2.00	4,511	5.5	$0.65	4,223	$0.58
$2.50 to $3.60	3,499	3.2	$2.95	1,607	$2.78
$5.15 to $7.60	2,255	2.7	$6.37	1,292	$6.38
$0.50 to $7.62	10,265	4.1	$2.69	7,122	$2.13

8. 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) are matched 50% by the Company in 2001 and increasing 10% per year thereafter to a maximum of 100%. The cost of Company contributions to the plan during 2002 and 2001 amounted to $0.1 million per year.

9. SEGMENT INFORMATION

Geographic segment results from operations for the years ended December 31, 2002, 2001 and 2000 are detailed below. The Company maintains a corporate office in Canada with its operational office in the U.S. For this section any amounts for Canada are included in the U.S. segment.

	Year Ended December 31, 2002		
	U.S.	China	Total
Oil and gas revenue	$ 5,099	$ 3,230	$ 8,329
Interest income	108		108
	5,207	3,230	8,437
Operating costs	2,351	1,490	3,841
Depletion and depreciation	2,110	1,202	3,312
	4,461	2,692	7,153
Segment income before the following	$ 746	$ 538	1,284
Write off of GTL assets *(Note 4)*			2,436
Project identification costs			733
General and administrative			4,934
Net loss			$ 6,819
Capital expenditures:			
Oil and gas	$ 13,305	$ 3,626	$ 16,931
Gas-to-liquids			1,897
			$ 18,828
Identifiable Assets:			
Oil & gas	$ 64,448	$ 25,281	$ 89,729
Gas-to-liquids			17,359
			$ 107,088

	Year Ended December 31, 2001		
	U.S.	China	Total
Oil and gas revenue	$ 5,101	$ 4,043	$ 9,144
Interest income	578		578
	5,679	4,043	9,722
Operating costs	2,421	2,337	4,758
Depletion and depreciation	2,117	1,124	3,241
Provision for impairment *(Note 11)*	14,000		14,000
	18,538	3,461	21,999

Segment loss (income) before the following	$12,859	$ (582)	12,277
Project identification costs			6,210
General and administrative			2,635
Net loss			$ 21,122
Capital expenditures:			
Oil and gas	$33,799	$ 6,568	$ 40,367
Gas-to-liquids			3,889
			$ 44,256
Identifiable Assets:			
Oil and gas	$61,750	$25,067	$ 86,817
Gas-to-liquids			17,186
			$104,003

	Year Ended December 31, 2000		
	U.S.	China	Total
Oil and gas revenue	$ 851	$	$ 851
Interest income	982	8	990
	1,833	8	1,841
Operating costs	787		787
Depletion and depreciation	310	31	341
	1,097	31	1,128
Segment income (loss) before the following	$ 736	$ (23)	713
Project identification costs			3,732
General and administrative			2,914
Gain on sale of Russian projects *(Note 12)*			(12,222)
Russian litigation *(Note 12)*			860
Net income			$ 5,429
Capital expenditures:			
Oil and gas	$22,815	$ 5,676	$ 28,491
Gas-to-liquids			13,253
			$ 41,744
Identifiable Assets:			
Oil and gas	$65,711	$20,836	$ 86,547
Gas-to-liquids			13,253
			$ 99,800

10. 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.

In September 2002, the Company entered into a costless collar derivative to hedge the cash flow from the sale of 91,000 barrels of oil production over a six-month period starting October 2002. The hedge has a ceiling price of $28.95 per barrel and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. In conjunction with this hedge, the Company posted collateral of $0.6 million as security for the hedge. The collateral accrues interest at the U.S. Federal Funds rate and is returnable to the Company on demand upon expiration of the hedge. As at December 31, 2002 the $0.6 million collateral is included in other current assets.

Gains and losses on derivatives are recognized in earnings as they are realized. As at December 31, 2002, the Company had insignificant realized gains or losses on derivative transactions and the mark-to-market value of these derivatives is a liability of $0.1 million.

11. PROVISION FOR IMPAIRMENT

Provision for impairment amounts calculated for U.S. oil and gas properties is $14.0 million for 2001. No provisions for impairment of oil and gas properties are required for 2002 and 2000.

12. GAIN ON SALE OF RUSSIAN PROJECTS

In August 2000, a negotiated settlement was reached resulting in the disposition of the Company s Russian projects for cash proceeds of $28.2 million, net of $0.8 million of settlement and severance costs. The proceeds exceeded the then carrying value of the Company s investment in the Russian projects and the resulting gain of $12.2 million is included in income.

13. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. Details of the determination of the actual income tax expense for each of the three years are detailed below. The loss of approximately $35.0 million from the Russian operations, being the aggregate investment, not including accounting write downs, less proceeds received on settlement will be a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely.

	Year Ended December 31,		
	2002	2001	2000
Source loss (income) before income taxes	$ 6,819	$21,122	$(5,429)
Composite statutory income tax rate	43.20%	43.20%	43.20%
Expected income tax (recovery)	$(2,946)	$ (9,125)	$ 2,345
Application of tax benefits not recognized previously			(4,910)
Tax benefit not recognized	2,946	9,125	2,565
Income tax expense	$	$	$

The tax loss carry-forwards in Canada are Cdn. $47.7 million and in the U.S. $51.5 million. The tax losses carry-forward in Canada expire between 2003 and 2009, in the U.S. between 2018 and 2022. In China, the Company has available for carry-forward against future Chinese income $37.3 million of cost basis. The Company s carrying value of assets for accounting purposes is $32.6 million greater than that available for tax purposes. Due to the uncertainty of utilizing these net tax assets, the Company has made a valuation allowance of an equal amount against these potential recoverable amounts as detailed below.

	As at December 31,		
	2002	2001	2000
Future net tax assets	$ 31,607	$ 27,082	$ 23,909
Valuation allowance	(31,607)	(27,082)	(23,909)
Net future tax liability	$	$	$

14. NET INCOME (LOSS) PER SHARE

The diluted earnings per share calculations for the years presented did not include the following items because their effect was anti-dilutive:

	Year Ended December 31,		
	2002	2001	2000
Stock options	2,986,000	4,018,000	
Convertible debenture	1,299,000	545,000	525,000
	4,285,000	4,563,000	525,000

The number of shares used to calculate diluted earnings per share for the year ended December 31, 2000 of 124,549,000 included the weighted average number of shares outstanding of 119,719,000 plus 4,802,000 shares related to the dilutive effect of stock options and 28,000 shares related to share purchase warrants.

Additionally, the diluted earnings per share calculations did not include the following weighted average items because the exercise prices exceeded the average market prices of the common shares:

	Year Ended December 31,		
	2002	2001	2000
Warrants		2,500,000	514,000
Stock options	5,359,000	240,000	724,000
	5,359,000	2,740,000	1,238,000

15. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and 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 $1.2 million for 2002, $2.7 million for 2001 and $1.6 million for 2000. In addition, a company controlled by a director provides consulting services to the Company. Consulting services and out of pocket expenses paid to this company were $0.4 million for 2002, $0.7 million for 2001 and $0.5 million for 2000. At year-end, amounts included in accounts payable under these arrangements totaled $0.8 million in 2002 and $1.1 million in 2001.

In December 2002, the Company borrowed $0.5 million from a related company controlled by a director of the Company, which was outstanding at year-end. (See Note 5)

16. COMMITMENTS AND CONTINGENCIES

With the signing of the production-sharing contract in September 2002 for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. If the Company does not complete the minimum exploration program it will be obligated to pay, to PetroChina, the cash equivalent of the deficiency in the work program. The estimated cost of the minimum exploration program is $18.0 million.

The Company will either suspend or abandon Northwest Lost Hills #1-22 pending final concurrence with Aera. If the well is abandoned, the Company would be obligated for its share of the costs to plug and abandon the well, which is estimated to be $1.1 million. There is no provision in the balance sheet for this contingent obligation.

17. LEASE COMMITMENTS

For the year ended December 31, 2002, the Company expended $0.6 million on operating leases relating to the rental of office space, which expire between April 2003 and March 2007. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses. As at December 31, 2002, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2003	$ 363
2004	162
2005	149
2006	149
2007	37
Total minimum lease payments	$ 860

18. SUBSEQUENT EVENT

In February 2003, the Company obtained bank financing for up to $5.0 million to construct facilities and drill an estimated 20 additional wells in the southern expansion of South Midway. Interest only is payable in the first year of the loan at 0.25% above the bank s prime rate or 2.75% over the London Inter-Bank Offered Rate (LIBOR) at the option of the Company. After the first year, the loan is repayable over three years plus interest at 0.50% above the bank s prime rate or 3.0% over LIBOR, at the option of the Company. The loan is secured by all the Company s rights and interests in the South Midway properties.

19. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP)

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, which were mentioned in Note 2. Where these matters impact the financial statements, the details of the differences are as follows:

Consolidated Statements of Loss (Income)

As discussed under Oil and Gas Properties in this note, there is a difference in performing the ceiling test evaluation under full cost accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP as at December 31, 2001 required an additional $10.0 million provision for impairment with respect to the Company s China properties.

In addition, the capitalization of development costs permitted under Canadian GAAP in connection with our GTL prospects is not permitted under U.S. GAAP.

The Company, in connection with its initial public offering in June 1997, placed in escrow 31,457,000 common shares held by certain shareholders, to be released one-third per year on the succeeding three anniversary dates of the public offering. For Canadian GAAP, as the release of shares from escrow is based on time rather than on any performance criteria, these shares are considered issued and outstanding and form part of the calculation of earnings and fully dilutive earnings per share for 2000. Under U.S. GAAP, these escrow shares are considered issued and outstanding only after they are released from escrow.

Under U.S. GAAP, interest income and gain on sale of Russian projects would be classified as other income.

The application of U.S. GAAP has the following effects on net loss (income) and net loss (income) per share as reported:

	Year Ended December 31,		
	2002	2001	2000
Net loss (income) under Canadian GAAP	$ 6,819	$ 21,122	$ (5,429)
Additional provision for impairment under U.S. GAAP		10,000	
Depletion adjustment China	(78)		
Write off of GTL development costs under U.S. GAAP, net	1,461	5,142	
Net loss (income) under U.S. GAAP	$ 8,202	$ 36,264	$ (5,429)
Net loss (income) per share under U.S. GAAP			
Basic	$ 0.06	$ 0.28	$ (0.05)
Diluted	$ 0.06	$ 0.28	$ (0.05)
Weighted average shares outstanding under U.S. GAAP (in thousands)			
Basic	142,314	128,598	115,065
Diluted	142,314	128,598	119,895

Under U.S. GAAP, changes in the fair value of derivative instruments that meet specific cash-flow hedge accounting criteria are reported in other comprehensive income (OCI). The gains and losses on cash-flow hedge transactions that are reported in OCI are reclassified to earnings in the period in which earnings are affected by changes in the cash flow of the underlying hedged item. The Company s hedging contracts qualify for hedge accounting treatment. The mark-to-market value of these derivatives as at December 31, 2002 is a liability of $0.1 million, which comprises the balance of OCI as at December 31, 2002.

Stock based compensation

The Company has a stock-based compensation plan as more fully described in Note 7. With regards to its stock option plan, the Company applies APB Opinion No. 25, as interpreted by FASB (FIN) 44, in accounting for this plan and accordingly no compensation cost has been recognized for stock options issued to employees and directors. Had 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 (income) and net loss (income) per share would have been reduced to the pro forma amounts indicated below:

	Year Ended December 31,		
	2002	2001	2000
Net loss (income) under U.S. GAAP	$ 8,202	$ 36,264	$ (5,429)
Stock-based compensation expense determined under fair-value based method for all awards	1,885	1,827	2,140
Pro forma net loss (income) under U.S. GAAP	$ 10,087	$ 38,091	$ (3,289)
Net loss (income) per common share under U.S. GAAP:			
Basic as reported	$ 0.06	$ 0.28	$ (0.05)
Basic pro forma	$ 0.07	$ 0.30	$ (0.03)
Diluted as reported	$ 0.06	$ 0.28	$ (0.04)
Diluted pro forma	$ 0.07	$ 0.30	$ (0.03)
Stock options granted during period (thousands)	1,870	846	1,991
Weighted average exercise price	$ 1.92	$ 2.99	$ 4.29
Weighted average fair value of options granted during the period	$ 1.07	$ 1.92	$ 2.32

The foregoing is calculated in accordance with Black-Scholes option pricing model, using the following data and assumptions: 59% to 108% price volatility, using the prior one to three-year weekly average prices of the Company s common shares; expected dividend yield of 0%; option terms to expiry of 5 to 10 years, as defined by the option agreements; risk-free rate of return as of the date of the grant of 4.35% to 5.70%, based on one and five year Government of Canada Bond yields.

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effects on balance sheet items as reported:

Shareholders Equity

Shareholders equity at December 31, 2002 under Canadian GAAP	$100,548
Adjustment to ascribed value of shares issued for royalty interests	1,358
Impairment provision for China properties required under U.S. GAAP	(10,000)
Depletion adjustment China	78
Write off of GTL development costs required under U.S. GAAP	(6,603)
OCI Derivative mark- to-market adjustment	(102)
Shareholders equity at December 31, 2002 under U.S. GAAP	$ 85,279
Shareholders equity at December 31, 2001 under Canadian GAAP	$ 96,897
Adjustment to ascribed value of shares issued for royalty interests *(Note 4)*	1,358
Impairment provision for China properties required under U.S. GAAP	(10,000)
Write off of GTL development costs required under U.S. GAAP	(5,142)
Shareholders equity at December 31, 2001 under U.S. GAAP	$ 83,113

The shareholders approved, on June 22, 1999, the reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the 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 deficit each are increased by $74.4 million at December 31, 2002 and 2001. As a result, shareholders equity under U.S. GAAP would comprise the following:

	As at December 31,	
	2002	**2001**
Share capital (including adjustments above)	$ 206,925	$ 196,205
Deficit (including adjustments above)	(121,544)	(113,092)
Accumulated other comprehensive income	(102)	
	$ 85,279	$ 83,113

Oil and Gas Properties

There are certain differences between the full cost method of accounting for oil and gas assets as applied in Canada and as applied in the U.S. The principal difference results in the method of performing ceiling test evaluations under the full cost accounting rules. Under Canadian GAAP, non-discounted future net revenues from oil and gas production, less an estimate for future general and administrative expenses, financing costs and income taxes are compared to the carrying value of the depletable petroleum properties, whereas for U.S. GAAP future net revenues are discounted to present value at 10% per annum and compared to the carrying value of the depletable petroleum properties. The Company has performed the ceiling test in accordance with U.S. GAAP and determined that there would be an additional provision for impairment required in connection with the Company s China properties of $10.0 million for 2001. No impairment provisions are required for 2002 or 2000.

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of royalty rights is $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.

The categories of costs included in the cost of oil and gas properties, equipment and GTL investments, including the adjustments in accordance with U.S. GAAP, to the ascribed value of shares issued for royalty interests of $1.4 million, an additional provision for impairment of the Company s China properties of $10.0 million and the write off of GTL development costs are as follows:

	As at December 31,		
	2002	**2001**	**2000**
Property acquisition costs	$ 16,868	$ 15,956	$10,268
Royalty rights acquired	10,582	10,582	6,539
Exploration costs	35,209	20,918	9,373
Development costs	41,639	45,325	26,414
GTL license, investment and feasibility studies	10,000	12,000	13,253
Support equipment	493	468	368
	114,791	105,249	66,215
Accumulated depletion and depreciation	(6,523)	(3,437)	(397)
Provision for impairment	(24,000)	(24,000)	
	$ 84,268	$ 77,812	$65,818

As at December 31, 2002, the costs of unevaluated properties included in capital assets are as follows:

		Incurred In			
	Total	**2002**	**2001**	**2000**	**1998 &1999**
Property acquisition costs	$16,696	$ 1,959	$ 9,877	$4,330	$ 530
Royalty rights acquired	9,223		3,900	1,197	4,126
Exploration costs	22,044	9,338	8,304	2,092	2,310
	$47,963	$11,297	$22,081	$7,619	$6,966

Accounts Payable and Accrued Liabilities

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

	As at December 31,	
	2002	**2001**
Accounts payable	$4,387	$5,144
Accrued salaries and related expenses	348	782
Fair market value of oil hedge	102	
Accrued interest	10	10
Other accruals	52	38
Total	$4,899	$5,974

Consolidated Statements of Cash Flow

As a result of the write-off of GTL development costs required under U.S. GAAP, the statement of cash flow as reported would result in cash deficiencies from operating activities of $4.7 million and $2.7 million for 2002 and 2001, respectively, and capital spending reported under investing activities would be $16.9 million and $36.6 million for 2002 and 2001, respectively.

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

In June 2001, the FASB approved SFAS No. 143, Accounting for Asset Retirement Obligations , which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Management does not believe that SFAS No. 143 will have a material impact on the Company s financial statements.

In June 2002, the FASB approved SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities which addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Task Force Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit and Activity (including Certain Costs Incurred in a Restructuring). This Statement is effective for fiscal years beginning after December 31, 2002. Management does not believe that SFAS No. 146 will have a material impact on the Company s financial statements.

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 working interest share of reserves net of royalties. The reserves for 2002, 2001 and 2000 in the U.S. are based on estimates by the independent petroleum engineering firm of Joe C. Neal & Associates and Allan Spivak Engineering. In China, the reserves are based on estimates by the independent petroleum engineering firm of Gilbert Laustsen Jung Associates Ltd.

The Company s net proved and net proved developed oil and gas reserves are as follows:

	Oil	Gas
	(MBbl)	(MMcf)
Net proved reserves, December 31, 1999	20,848	
Extensions and discoveries	4,803	6,301
Production	(133)	(5)
Revisions to previous estimates	276	
Net proved reserves, December 31, 2000	25,794	6,296
Extensions and discoveries	923	651
Production	(377)	(127)
Revisions to previous estimates	(2,542)	(5,189)
Net proved reserves, December 31, 2001	23,798	1,631
Extensions and discoveries	710	63
Production	(350)	(103)
Revisions to previous estimates	(2,881)	(101)
Sale of reserves	(3,889)	(671)
Net proved reserves, December 31, 2002	17,388	819
Net proved developed reserves		
December 31, 2000	1,573	984
December 31, 2001	1,808	1,215
December 31, 2002	1,179	819

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 has been computed using period end prices of $29.04 per barrel of oil ($15.37 per barrel in 2001 and $23.95 per barrel in 2000) and $5.30 per Mcf of gas ($2.76 per Mcf in 2001 and $5.65 per Mcf in 2000) and costs and period end statutory tax rates. A discount rate of 10% has been 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 are as follows:

	2002	2001	2000
Future cash inflows	$513,313	$370,344	$653,419
Future development and restoration costs	134,452	137,581	162,399
Future production costs	150,828	156,103	145,130
Future income taxes	52,656	5,526	102,831
Future net cash flows	175,377	71,134	243,059
10% annual discount	94,110	52,845	141,823
Standardized measure	$ 81,267	$ 18,289	$101,236

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

	2002	2001	2000
Sale of oil & gas net of production costs	$ (4,488)	$ (4,386)	$ (64)
Revenue credited to China property costs			(2,940)
Net changes in pricing and productions costs	164,210	(110,584)	(3,433)
Sale of reserves	(47,685)		
Discoveries and extensions	9,585	4,955	19,266
Revisions of previous estimates	(63,467)	22,167	1,707
Net change in future development costs	3,230	(1,640)	9,611
Accretion of discount	1,593	6,541	5,979
Increase (decrease)	62,978	(82,947)	30,126
Standardized measure, beginning of year	18,289	101,236	71,110
Standardized measure, end of year	$ 81,267	$ 18,289	$101,236

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities for the following periods ended:

	Year Ended December 31,	
	2002	2001
Property Acquisition		
Proved	$	$
Unproved	913	5,688
Royalty rights		4,043
Exploration	10,841	11,545
Development	5,178	19,091

	$16,932	$40,367

Depletion, per unit of net production, before provision for impairment:

U.S.	
Year ended December 31, 2002	$8.39
Year ended December 31, 2001	$8.12
Year ended December 31, 2000	$8.70
China	
Year ended December 31, 2002	$8.30
Year ended December 31, 2001	$6.79

Results of Producing Activities:

	Year Ended December 31,		
	2002	2001	2000
Oil and gas revenue	$8,329	$ 9,144	$ 851
Operating costs	3,841	4,758	787
Depletion (including provision for impairment)	3,108	27,133	275
Results of operations from producing activities	$1,380	$(22,747)	$(211)

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 71 Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 present); President, Cathedral Mountain Corporation (1997 present); President and Chief Executive Officer, Occidental Oil and Gas Corporation (1986-1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 52 Hong Kong	Deputy Chairman (since June, 1999) and Director (since February 1995)	Chairman and President, Ivanhoe Capital Corporation, a Singapore based venture capital company principally involved in establishing and financing international mining and exploration companies
E. LEON DANIEL, age 66 Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); Vice President Engineering, Drilling and Production, Occidental Petroleum Corporation(1997-1998)
JOHN A. CARVER, age 70 Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum Corporation (1997-1998)
R. EDWARD FLOOD, age 57 Reno, Nevada	Director (since June, 1999)	Deputy Chairman, Ivanhoe Mines Ltd. (May, 1999 present); Mining Analyst, Haywood Securities (May, 1999 September 2001) President, Ivanhoe Mines Ltd. (1995-1999)
SHUN-ICHI SHIMIZU, age 62 Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 to present)
HOWARD R. BALLOCH, age 51 Beijing, China	Director (since January, 2002)	President, White Birch International Ltd. (July 2001 present); President, Canada China Business Council (July 2001 present); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 July 2001)
JOHN O KEEFE, age 54 Houston, Texas	Executive Vice-President, Investor Relations and Chief Financial Officer (since September, 2000)	Executive Vice-President, Investor Relations and Chief Financial Officer of Ivanhoe Energy Inc. (September 2000 present); Vice-President, Investor Relations of Santa Fe Snyder Corporation (1999 September 2000); Director, Investor Relations of Oryx Energy Company (1991-1999)

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
PATRICK CHUA, age 47 Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 present); President and Director of Sunwing Energy Ltd. (Bermuda) (March 2000 present): Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 June, 1999)
GERALD MOENCH, age 54 Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 present); President and Director, Sunwing Energy Ltd. (July, 1997 June, 1999)

Each of our directors was elected at our last annual general meeting of shareholders held on May 16, 2002. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director s office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation Committee. The members of the Audit Committee are Messrs. Edward Flood, Howard Balloch and Shun-Ichi Shimizu. Mr. Ed Flood, an independent director of the Company, has been determined by the Board of Directors to be an Audit Committee financial expert. The members of the Compensation Committee are Messrs. David Martin, Edward Flood and Howard Balloch.

Management is responsible for our financial reporting process including our system of internal control and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent auditors are responsible for auditing those financial statements. The members of the audit committee are not our employees, and are not professional accountants or auditors. The audit committee s primary purpose is to assist the Board of Directors to fulfill its oversight responsibilities by reviewing the financial information provided to shareholders and others, the systems of internal controls which management has established to preserve our assets and the audit process. It is not the audit committee s duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the audit committee has relied on management s representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the representations of the independent auditors included in their report on our financial statements.

Based solely on a review of the reports furnished to us, we believe that during 2002 all of our directors, executive officers and 10% shareholders complied with the applicable requirements for reporting initial ownership and changes in ownership of our common shares.

ITEM 11. EXECUTIVE COMPENSATION

The following executive compensation disclosure relates to our President and Chief Executive Officer as at December 31, 2002, and each of our four most highly compensated executive officers (collectively, the named executive officers) whose annual compensation exceeded $100,000 in the year ended December 31, 2002. During the years ended December 31, 2002, 2001 and 2000 the total compensation paid to those of our named executive officers was $1.1 million, $0.8 million and $0.9 million, respectively.

Summary Compensation

We paid the following compensation during the years ending December 31, 2002, 2001 and 2000 to each of our named executive officers.

SUMMARY COMPENSATION TABLE

		Annual Compensation			Long Term Compensation			
					Awards	$	Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation	Securities Under Options Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts ($)	All Other Compensation ($)
E. LEON DANIEL	2002	266,500		243(1)				5,415(2)
President & Chief	2001	150,000		170(1)				
Executive Officer	2000	200,000	22,000		500,000			
PATRICK CHUA	2002	182,970		5,083(1)	60,000			
Executive Vice	2001	180,000		12,794(1)				
President	2000	180,000		6,241(1)				
JOHN O KEEFE	2002	219,845		4,537(1)	75,000			7,200(2)
Chief Financial Officer	2001	174,955		3,659(1)	250,000			5,250(2)
Executive Vice	2000	58,333			250,000			
President Investor Relations								
DAVID R. MARTIN	2002	253,167		1,077(1)				7,200(2)
Chairman	2001	150,000		894(1)				3,000(2)
	2000	50,000	110,000					
GERALD MOENCH	2002	152,475		3,535(1)	50,000			
Executive Vice	2001	150,000		3,085(1)				
President	2000	150,000		3,857(1)				

(1) Includes premiums paid by us on behalf of the named executive officer for medical, dental and other health insurance coverage.

(2) Company s matching contribution to the 401(k) plan.

Options

We granted the following Options to our named executive officers in the financial year ended December 31, 2002:

OPTION GRANTS IN LAST FISCAL YEAR

Name	Number of Securities Underlying Options Granted (#)	Percent of Total Options Granted to Employees in Fiscal Year	Exercise of Base Price (Cdn$/Sh)	Expiration Date	Grant Date Present Value $Cdn(1)
JOHN O KEEFE	75,000	3.20%	$3.10	May, 30 2007	$3.10
PATRICK CHUA	60,000	2.56%	$3.10	May, 30 2007	$3.10
GERRY MOENCH	50,000	2.13%	$3.10	May, 30 2007	$3.10

(1) Equal to or greater than the weighted average price of our common shares on The Toronto Stock Exchange for the five trading days preceding the date of a grant.

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Aggregated Option Exercises

No options were exercised by any of the named executive officers during the financial year ended December 31, 2002.

Pension Plans

We do not presently provide a pension plan for our employees. However, 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) are matched by the Company 50% starting in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company s matching contributions to the 401(k) Plan during 2002 and 2001 were $0.1 million in each of those years.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

We have no written employment contracts or termination of employment or change of control arrangement with any of our directors or named executive officers except for Messrs. E. Leon Daniel and John O Keefe. Both contracts allow us to terminate the employee for cause and if this were to happen, the employee has no entitlement to claim any compensation with respect to the termination. Neither contract contains a change of control arrangement. With respect to Mr. Daniel s contract, the term of employment is for a period of five years, commencing on April 30, 2002, unless terminated in accordance with the provisions of the Agreement. His salary for services performed is at a rate of not less than $300,000 per year and he is eligible for a cash bonus and stock bonus each year, as determined by the Compensation Committee. Mr. Daniel s benefit programs are the same as those applicable to all of our employees. Either party may terminate the agreement with one year s notice to the other, however, we may terminate Mr. Daniel s employment at any time without notice by compensating him for the period after termination equivalent to one year s salary or until the expiration of the employment agreement, whichever is the shorter period of time. With respect to Mr. O Keefe s contract, his base salary is $200,000 per year, to be reviewed by the board of directors at least annually. Mr. O Keefe s benefit programs are the same as those applicable to all of our employees. Mr. O Keefe was granted an initial option to acquire 250,000 common shares of the Company, which vest over 4 years and expire on the 5th anniversary of the date of grant. We may terminate Mr. O Keefe s employment by delivering to him, one year s written notice, during which time we would continue to pay his salary and benefits. His initial option of 250,000 common shares would fully vest at the date of termination and he would be entitled to exercise the option within the maximum time permitted by the policies of the Toronto Stock Exchange. If Mr. O Keefe terminates his employment he will be entitled to exercise the vested shares, subject to the option, for the maximum time permitted by the policies of the Toronto Stock Exchange. In the event of Mr. O Keefe s death or permanent disability while in the employ of the Company, the remaining shares subject to his initial option would vest and his estate would be entitled to exercise the option, with respect to those shares, within the maximum time permitted by the policies of the Toronto Stock Exchange.

Director Compensation

All independent directors receive director fees of $2,000 per month. We did not pay any other cash or fixed compensation to our directors for acting as such. We reimburse our directors for expenses they reasonably incur in the performance of their duties as directors and they are also eligible to participate in our Employees and Directors Equity Incentive Plan. One of our non-executive directors, John A. Carver, was engaged as a full time employee effective January 1, 2002 and receives a salary in his capacity as an employee.

Employees and Directors Equity Incentive Plan

Our Employees and Directors Equity Incentive Plan, as amended (the Plan) consists of three component plans: a common share option plan (the Share Option Plan), a common share bonus plan (the Share Bonus Plan), and a common share purchase plan (the Share Purchase Plan). The purpose of the Plan is to advance our corporate interests, by encouraging equity participation by our directors, officers, employees and service providers through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the board of directors to grant options to acquire our common shares in favor of our directors, officers, employees and service providers. Options are subject to adjustment in the event of a subdivision or consolidation of our common shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers, employees and service providers, who are, in the opinion of our board of directors, in a position to contribute to our future growth and success.

In determining the number of common shares made subject to an option, we consider, among other things, the optionee s relative present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The board of directors determines the date of grant, the number of optioned common shares, the exercise price per share, the vesting period and the exercise period. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant.

Unless earlier terminated upon an optionee s death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

Share Bonus Plan

The Share Bonus Plan permits our board of directors to issue up to an aggregate maximum of 1,000,000 of our common shares as bonus awards to our directors, employees and service providers on a discretionary basis having regard to such merit criteria as the board of directors may determine. As of December 31, 2002 there were 62,579 shares available to be issued from the Share Bonus Plan.

Share Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the board of directors) of continuous service on a full-time basis and who are designated by the board of directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly installments. We then make contributions on a quarterly basis equal to the employee s contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant s behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares, which we may issue, or reserve for issuance under the Plan, is currently 15,000,000 common shares. Any increase is subject to Toronto Stock Exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares. As of December 31, 2002 there were 474,998 shares available to be issued from our Employees and Directors Equity Incentive Plan.

Our board of directors has the right to amend, modify or terminate our Equity Incentive Plan. However, any amendment to the Equity Incentive Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to Toronto Stock Exchange approval and the approval of our shareholders.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2002, our Compensation Committee consisted of Messrs. Edward Flood, Howard Balloch and David Martin. Mr. Martin is one of our named executive officers.

Board Compensation Committee Report on Executive Compensation

Our executive compensation program is administered by the Compensation Committee. The basic philosophy underlying our executive compensation program is that the interests of our executive officers should be aligned as closely as possible with the interests of Ivanhoe and its shareholders as a whole. Compensation for our senior executive officers is, accordingly, designed to reflect the following considerations: to provide a strong incentive to management to achieve our corporate goals each year; to ensure that the interests of management and of our shareholders are aligned; and to enable us to attract, retain and motivate the quality of people necessary to our business in the light of competition for qualified personnel. Our approach to compensation for senior executives and other employees is designed to recognize both corporate and individual performance, and the fact that competition for highly skilled employees is intense.

The compensation that we pay to our executive officers generally consists of cash, equity and equity incentives. Our compensation policy reflects a belief that an element of total compensation for our executive officers should be at risk in the form of stock options, so as to create a strong incentive to build shareholder value. The Compensation Committee oversees and sets the general guidelines and principles for the compensation packages for senior management. As well, the Compensation Committee assesses the individual performance of our senior executive officers and makes recommendations to the board of directors. Based on these recommendations, the board of directors makes decisions concerning the nature and scope of the compensation to be paid to our senior executive officers over and above their base salaries.

The specific relationship of corporate performance to executive compensation under our executive compensation program is created through equity compensation mechanisms. Incentive stock options, which vest and become exercisable through the effluxion of time, link the bulk of our equity-based executive compensation to shareholder return, measured by increases in the market price of our common shares. The Board of Directors may make discretionary bonus awards of common shares to our employees, including our executive officers. Such awards are intended to recognize extraordinary contributions to the achievement of corporate objectives or the fulfillment of defined business development goals and milestones tied to pre-determined equity incentives.

As part of a temporary program to reduce costs and preserve cash, the total cash compensation paid to our senior management personnel during 2002 was reduced by a minimum of 10%. In lieu of the foregone cash compensation, we issued to our senior management personnel common shares on the basis of one common share for each dollar of foregone salary. We believe that this is consistent with our basic compensation philosophy that the best interests of shareholders are served by having executive compensation meaningfully tied to corporate performance. It also reflects our stage of development, our limited history of earnings and the priority allocation of our limited financial resources to the development of our business.

The compensation paid to our Chief Executive Officer for the fiscal year ended December 31, 2002 was based on the same basic factors and criteria used to determine executive compensation generally. During 2002 our Chief Executive Officer elected to voluntarily forego approximately 15% of the cash compensation that would otherwise have been payable to him and to receive common shares in lieu of the foregone salary on the basis of one share for each dollar foregone. This increase in the ratio of cash compensation to equity-based compensation reflects his and our expectation that the contribution and efforts of the Chief Executive Officer will materially affect the extent to which, and how quickly, we are successful in developing our business, particularly as it relates to GTL, and creating shareholder value. The relative risks and rewards inherent in equity-based compensation are intended to be commensurate with the Chief Executive Officer s contribution and efforts.

The cash compensation payable to our Chief Executive Officer reflects the Compensation Committee s views as to what constitutes a fair and reasonable base salary for an executive with his skills, expertise and experience having due regard to the nature and stage of development of our business and our ability to pay. In assessing the cash compensation payable to the Chief Executive Officer, the members of the Compensation Committee have drawn upon their extensive resource industry experience but have not based the assessment on rates of cash compensation payable to other chief executive officers in the oil and gas industry. Ongoing consolidation in our industry is rapidly diminishing the number of peer companies of similar size and development, thereby making meaningful comparisons questionable in assessing and determining either the cash component or the equity component of our Chief Executive Officer s compensation.

We did not pay a cash bonus to our Chief Executive Officer during 2002. Accordingly, there is no measurable relationship between our performance, as reflected in our share price, our financial results or the development of our business, and the cash component of the Chief Executive Officer s compensation insofar as the cash component for 2002 consists solely of base salary. The value of the equity component of the Chief Executive Officer s compensation is exclusively determined with reference to our performance as measured by the appreciation or decline in the market price of our common shares.

Submitted on behalf of the Compensation Committee:

Mr. R. Edward Flood
Mr. David R. Martin
Mr. Howard R. Balloch

Performance Graph

The following graph and table compares the cumulative shareholder return on a $100 investment in common shares of the Company to a similar investment in companies comprising the TSE 300 Total Return Index, including dividend reinvestment, for the period from December 31, 1997 to December 31, 2002.

(PERFORMANCE GRAPH)

	Dec. 31, 1997	Dec. 31, 1998	Dec. 31, 1999	Dec. 31, 2000	Dec. 31, 2001	Dec. 31, 2002
Ivanhoe Energy Inc.	Cdn. $100	Cdn. $22	Cdn. $153	Cdn. $423	Cdn. $128	Cdn. $41
TSE 300 Total Return Index	Cdn. $100	Cdn. $97	Cdn. $126	Cdn. $133	Cdn. $115	Cdn. $99

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT
Except as set forth below, no person or group is known to beneficially own 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares at March 3, 2003.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class
Common Shares	Robert M. Friedland(2) Flat B, 31st Floor Primrose Court 56A Conduit Road Mid-Levels, Hong Kong	46,611,725	32.26%
Common Shares	Capital Research and Management Company 333 South Hope Street Los Angeles, California 90071	10,192,200	7.05%
Common Shares	Paul Stephens 388 Market Street Suite 200 San Francisco, California 94111	7,252,138	5.02%
Common Shares	Directors and Executive Officers as a Group (10 persons)	53,935,476(3)	36.02%

(1) Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) 46,194,620 outstanding common shares are held indirectly through Newstar Securities SRL, Premier Mines Ltd. and Evershine LLC, companies controlled by Mr. Friedland.

(3) Includes 5,288,677 common shares issuable upon the exercise of incentive stock options held by directors and executive officers as a group.

Security Ownership of Management

The following table sets forth the beneficial ownership at March 3, 2003 of our common shares by each of our directors, our named executive officers and by all of our directors and executive officers as a group:

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percentage of Class	Incentive Stock Options included in (a)
		(a)	(b)	(c)
Common Shares	David R. Martin	4,337,460	2.93	3,400,000
Common Shares	Robert M. Friedland	46,611,725	32.26	
Common Shares	E. Leon Daniel	959,957	0.66	466,667
Common Shares	John A. Carver	616,899	0.43	350,000
Common Shares	R. Edward Flood	105,029	0.07	80,000
Common Shares	Shun-ichi Shimizu	92,500	0.06	60,000
Common Shares	John O Keefe	421,586	0.29	315,000

Common Shares	Patrick Chua	578,120	0.40	412,000
Common Shares	Gerald Moench	172,200	0.12	, 165,000
Common Shares	Howard R. Balloch	40,000	0.03	40,000
Common Shares	All directors and executive officers as a group (10 persons)	53,935,476	36.02%	

See Item 5 for Securities Authorized for Issuance under Equity Compensation Plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Management and Others

In December 2002, the Company borrowed $0.5 million from Ivanhoe Capital Finance Ltd., a company wholly owned by Mr. Robert Friedland. The unsecured loan is due 90 days after written demand, on the closing date of obtaining equity financing or December 31, 2005 whichever occurs earliest. The loan bears interest at U.S. prime plus 3%.

Certain Business Relationships

We are parties to cost sharing agreements with other companies wholly owned by Mr. Robert M. Friedland. Through these agreements, we share office space, furnishings, equipment and communications facilities in Vancouver, Singapore and London and an aircraft on a cost recovery basis. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2002, our share of these costs was $1.2 million.

During the year ended December 31, 2002 a company controlled by Mr. Shun-ichi Shimizu received $0.4 million for consulting services and out of pocket expenses.

TABLE OF INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS

AND SENIOR OFFICERS

Name and Principal Position	Involvement of Issuer or Subsidiary	Largest Amount Outstanding During 2002	Amount Outstanding as at March 3, 2003
DAVID R. MARTIN Chairman	Loan Agreement	$218,711	$ 0
R. EDWARD FLOOD Director	Loan Agreement	$ 65,613	$ 0

We loaned Messrs. Martin and Flood Cdn. $200,000 and Cdn. $60,000, respectively, in January 2001 to facilitate their exercise of warrants to purchase 50,000 and 15,000 of our common shares, respectively. The loans bore interest at the Bank of Montreal prime rate as quoted from time to time and were secured by a pledge of the shares purchased under the loan agreement. The loans were to mature in January 2003. In December 2002, Messrs. Martin and Flood notified us in writing that they were electing to surrender for cancellation the common shares purchased with the proceeds of the loans in lieu of repaying the outstanding loan balances and accrued interest thereon.

ITEM 14. DISCLOSURE CONTROLS AND PROCEDURES

Within 90 days prior to the date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s CEO and CFO, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to the 1934 Securities Exchange Act. Based upon that evaluation, the CEO and CFO concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information required to be included in the Company s periodic SEC filings relating to the Company (including its consolidated subsidiaries). There were no significant changes in the our internal controls or in other factors that could significantly affect our internal controls subsequent to the date of their evaluation, nor any significant deficiencies or material weaknesses in such internal controls requiring corrective actions. As a result, no corrective actions were taken.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

The following financial statements and exhibits are filed as part of this Annual Report:

(a) 1. **Financial Statements:**

Deloitte & Touche, LLP Auditors Report on Consolidated

Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2002 and Consolidated Statements of Loss and Deficit and 2001 and ated Statements of Cash Flow of Ivanhoe Energy Inc. for the ded December 31, 2002, 2001 and 2000.
Consolid
years en

Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2002 and 2001

Consolidated Statements of Loss and Deficit of Ivanhoe Energy Inc. For the years ended December 31, 2002, 2001 and 2000.

Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2002, 2001 and 2000.
Inc. for the years ended December 31, 2002, 2001 and 2000.

2. **Financial Statement Schedules:**

Supplementary Disclosures about Oil and Gas Production Activities (Unaudited)

3. **Exhibits**

3.1 Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

3.2 Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

4.1 Amended and Restated Convertible Loan Agreement dated August 4, 1999 between Ivanhoe Energy Inc. and Linyi Holdings Ltd. (incorporated by reference to Exhibit 3.2 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.1 Petroleum Contract for Kongnan Block, Dagang Oilfield of the People s Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).

10.2 Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).

10.3 Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).

10.4 Employees and Directors Equity Incentive Plan (incorporated by reference to Exhibit 10.20 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).

10.5 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block. (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)

10.6 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Zitongxi and Zitondong blocks. (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002.)

10.7 Joint Venture Agreement and Operating Agreement dated 1 July 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Creslenn Ranch Area, Henderson County, Texas. (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002.)

10.8	Joint Venture Agreement and Operating Agreement dated 1 October 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas. (Incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.9	Modification Agreement for Petroleum Development Contract for Kongnan Block, Dagang Oilfield, the People s Republic of China, dated 24 October 2001. (Incorporated by reference to Exhibit 10.25 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.10	Amendment of Petroleum Contract for Petroleum Development and Production in Zhou 13 Block, Daqing Zhaozhou Oilfield, of the People s Republic of China dated 28 December 2001. (Incorporated by reference to Exhibit 10.26 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.11	Consulting Agreement dated 13 January 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC. (Incorporated by reference to Exhibit 10.27 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.12	Petroleum Contract dated September 2002 for Zitong Block, Sichuan Basin of the People s Republic of China
10.13	Strategic Development Alliance Letter Agreement dated September 26, 2002 between the Company and CITIC Energy Ltd.
10.14	Standstill Agreement dated October 29, 2002 between the Company and Linyi Holdings Limited
10.15	Loan Agreement dated 31 December 2002 between the Company and Ivanhoe Capital Finance Limited
21.1	Subsidiaries of Ivanhoe Energy Inc.
23.1	Consent of Gilbert Laustsen Jung Associates Ltd., Petroleum Engineers.
23.2	Consent of Allan Spivak Engineering.
23.3	Consent of Joe C. Neal & Associates.
99.1	Certification by the Chief Executive Officer Relating to a Periodic Report Containing Financial Statements
99.2	Certification by the Chief Financial Officer Relating to a Periodic Report Containing Financial Statements

(b) **Reports on Form 8-K:**

October 21, 2002	Agreement With CITIC Energy Inc. to form Strategic Alliance and joint development of Yudong Block if a production sharing contract with PetroChina Corporation is negotiated.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IVANHOE ENERGY INC.

By: /s/ E. LEON DANIEL

Name: E. Leon Daniel
Title: President and Chief Executive Officer

Dated: March 17, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ E. LEON DANIEL E. Leon Daniel	President, Chief Executive Officer and Director (Principal Executive Officer)	March 17, 2003
/s/ JOHN O KEEFE John O Keefe	Executive Vice-President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 17, 2003
/s/ DAVID MARTIN David Martin	Chairman of the Board and Director	March 17, 2003
/s/ ROBERT M. FRIEDLAND Robert M. Friedland	Deputy Chairman and Director	March 17, 2003
/s/ JOHN A. CARVER John A. Carver	Director	March 17, 2003
/s/ R. EDWARD FLOOD R. Edward Flood	Director	March 17, 2003
/s/ SHUN-ICHI SHIMIZU Shun-ichi Shimizu	Director	March 17, 2003
/s/ HOWARD BALLOCH Howard Balloch	Director	March 17, 2003

CERTIFICATION BY THE CHIEF EXECUTIVE OFFICER RELATING TO

INTERNAL DISCLOSURE CONTROLS AND PROCEDURES

I, E. Leon Daniel, certify that:

1. I have reviewed this annual report on Form 10-K of Ivanhoe Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a.) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b.) evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c.) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent functions):

   a.) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

   b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 17, 2003

Chief Executive Officer

By: /s/ E. LEON DANIEL

E. Leon Daniel

CERTIFICATION BY THE CHIEF FINANCIAL OFFICER RELATING TO

INTERNAL DISCLOSURE CONTROLS AND PROCEDURES

I, John O Keefe, certify that:

1. I have reviewed this annual report on Form 10-K of Ivanhoe Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the periods covered by this annual report.

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

   a. designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b. evaluated the effectiveness of the registrant s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant s auditors and the audit committee of registrant s board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant s ability to record, process, summarize and report financial data and have identified for the registrant s auditors any material weaknesses in internal controls; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant s internal controls; and

6. The registrant s other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 17, 2003

Chief Financial Officer

By: /s/ JOHN O KEEFE

John O Keefe

EXHIBIT INDEX

Exhibit No.	Description
3.1	Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
3.2	Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
4.1	Amended and Restated Convertible Loan Agreement dated August 4, 1999 between Ivanhoe Energy Inc. and Linyi Holdings Ltd. (incorporated by reference to Exhibit 3.2 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People s Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000).
10.2	Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000).
10.3	Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
10.4	Employees and Directors Equity Incentive Plan (incorporated by reference to Exhibit 10.20 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001).
10.5	Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block. (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.6	Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Zitongxi and Zitondong blocks. (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002.)
10.7	Joint Venture Agreement and Operating Agreement dated 1 July 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Creslenn Ranch Area, Henderson County, Texas. (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002.)
10.8	Joint Venture Agreement and Operating Agreement dated 1 October 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas. (Incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.9	Modification Agreement for Petroleum Development Contract for Kongnan Block, Dagang Oilfield, the People s Republic of China, dated 24 October 2001. (Incorporated by reference to Exhibit 10.25 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.10	Amendment of Petroleum Contract for Petroleum development and Production in Zhou 13 Block, Daqing Zhaozhou Oilfield, of the People s Republic of China dated 28 December 2001. (Incorporated by reference to Exhibit 10.26 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.11	Consulting Agreement dated 13 January 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC. (Incorporated by reference to Exhibit 10.27 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.12	Petroleum Contract dated September 2002 for Zitong Block, Sichuan Basin of the People s Republic of China
10.13	Strategic Development Alliance Letter Agreement dated September 26, 2002 between the Company and CITIC Energy Ltd.
10.14	Standstill Agreement dated October 29, 2002 between the Company and Linyi Holdings Limited
10.15	Loan Agreement dated 31 December 2002 between the Company and Ivanhoe Capital Finance Limited
21.1	Subsidiaries of Ivanhoe Energy Inc.
23.1	Consent of Gilbert Laustsen Jung Associates Ltd., Petroleum Engineers.
23.2	Consent of Allan Spivak Engineering.

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Exhibit No.	Description
23.3	Consent of Joe C. Neal & Associates.
99.1	Certification by the Chief Executive Officer Relating to a Periodic Report Containing Financial Statements
99.2	Certification by the Chief Financial Officer Relating to a Periodic Report Containing Financial Statements

(b) Reports on Form 8-K:

October 21, 2002.	Agreement With CITIC Energy Inc. to form Strategic Alliance and joint development of Yudong Block if a production sharing contract with PetroChina Corporation is negotiated.