IVANHOE ENERGY INC
Form 10-Q
November 08, 2007

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**98-0372413**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
Suite 654 999 Canada Place Vancouver, British Columbia, Canada	**V6C 3E1**
(Address of principal executive office)	*(zip code)*

(604) 688-8323

(registrant s telephone number, including area code)

No Changes

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant is large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The number of shares of the registrant s capital stock outstanding as of September 30, 2007 was 242,809,513 Common Shares, no par value.

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Part I Financial Information

Item 1 Financial Statements
IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	September 30, 2007	December 31, 2006
Assets		
Current Assets		
Cash and cash equivalents	**$ 14,779**	$ 13,879
Accounts receivable	**8,027**	7,435
Advance	**925**	
Prepaid and other current assets	**287**	773
	24,018	22,087
Oil and gas properties and investments, net	**116,150**	121,918
Intangible assets technology	**102,153**	102,153
Long term assets	**893**	2,386
	$ 243,214	$ 248,544
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 10,417**	$ 9,428
Notes payable current portion	**6,188**	2,147
Asset retirement obligations current portion	**748**	
Derivative instruments	**3,175**	493
	20,528	12,068
Long term debt	**7,937**	4,237
Asset retirement obligations	**1,930**	1,953
Long term obligation	**1,900**	1,900
Commitments and contingencies		
Shareholders Equity		
Share capital, issued 242,809,513 common shares; December 31, 2006 241,215,798 common shares	**319,817**	318,725
Purchase warrants	**23,422**	23,955

Contributed surplus		**8,821**		6,489
Accumulated deficit		**(141,141)**		(120,783)
		210,919		228,386
	$	**243,214**	$	248,544

(See accompanying notes)

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IVANHOE ENERGY INC.
Unaudited Condensed Consolidated Statements of Operations and Accumulated Deficit
(stated in thousands of U.S. Dollars, except per share amounts)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Revenue				
Oil and gas revenue	**$ 10,864**	$ 13,745	**$ 30,249**	$ 36,385
Loss on derivative instruments	**(2,153)**		**(2,928)**	
Interest income	**112**	270	**348**	578
	8,823	14,015	**27,669**	36,963
Expenses				
Operating costs	**4,266**	4,724	**12,174**	11,298
General and administrative	**2,725**	2,921	**8,981**	7,648
Business and technology development	**2,831**	2,043	**7,341**	5,159
Depletion and depreciation	**6,044**	7,772	**18,960**	24,808
Interest expense and financing costs	**189**	211	**571**	737
Write off of deferred acquisition costs		732		732
Provision for impairment				750
	16,055	18,403	**48,027**	51,132
Net Loss	**(7,232)**	(4,388)	**(20,358)**	(14,169)
Accumulated Deficit, beginning of period	**(133,909)**	(105,072)	**(120,783)**	(95,291)
Accumulated Deficit, end of period	**$ (141,141)**	$ (109,460)	**$ (141,141)**	$ (109,460)
Net Loss per share Basic and Diluted	**$ (0.03)**	$ (0.02)	**$ (0.08)**	$ (0.06)
Weighted Average Number of Shares (in thousands)	**242,747**	241,181	**241,812**	233,766

(See accompanying notes)

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Operating Activities				
Net loss	**$ (7,232)**	$ (4,388)	**$ (20,358)**	$ (14,169)
Items not requiring use of cash:				
Depletion and depreciation	**6,044**	7,772	**18,960**	24,808
Provision for impairment				750
Stock based compensation	**758**	1,105	**2,613**	2,174
Write off of deferred acquisition costs		732		732
Unrealized loss on derivative instruments	**1,730**		**2,682**	
Other	**151**	(147)	**481**	360
Changes in non-cash working capital items	**315**	279	**188**	(3,600)
	1,766	5,353	**4,566**	11,055
Investing Activities				
Capital investments	**(9,100)**	(5,019)	**(22,557)**	(13,622)
Merger and acquisition related costs		(230)		(732)
Proceeds from sale of assets			**1,000**	5,350
Recovery of HTL ™ investments			**9,000**	
Advance repayments (payments)			**400**	(125)
Other	**(47)**	(45)	**28**	(114)
Changes in non-cash working capital items	**2,189**	(5,306)	**695**	(8,085)
	(6,958)	(10,600)	**(11,434)**	(17,328)
Financing Activities				
Shares issued on private placements, net of share issue costs				25,298
Proceeds from exercise of options	**113**	22	**278**	471
Proceeds from debt obligations, net of financing costs	**9,335**		**9,335**	
Payments of debt obligations	**(615)**	(1,031)	**(1,845)**	(6,685)
Other	**62**	(17)		
	8,895	(1,026)	**7,768**	19,084
Increase (decrease) in cash and cash equivalents, for the period	**3,703**	(6,273)	**900**	12,811
Cash and cash equivalents, beginning of period	**11,076**	25,808	**13,879**	6,724
Cash and cash equivalents, end of period	**$ 14,779**	$ 19,535	**$ 14,779**	$ 19,535

(See accompanying notes)

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Notes to the Condensed Consolidated Financial Statements
September 30, 2007
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. GOING CONCERN AND BASIS OF PRESENTATION

The Company s accounting policies are in accordance with accounting principles generally accepted in Canada. These policies are consistent with accounting principles generally accepted in the U.S., except as outlined in Note 13. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2006 consolidated financial statements. These interim condensed consolidated financial statements do not include all disclosures normally provided in annual consolidated financial statements and should be read in conjunction with the most recent annual consolidated financial statements. The December 31, 2006 condensed consolidated balance sheet was derived from the audited consolidated financial statements, but does not include all disclosures required by generally accepted accounting principles (**GAAP**) in Canada and the U.S. In the opinion of management, all adjustments (which included normal recurring adjustments) necessary for the fair presentation for the interim periods have been made. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The Company s financial statements as at and for the nine-month period ended September 30, 2007 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. The Company incurred a net loss of $20.4 million for the nine-month period ended September 30, 2007, and as at September 30, 2007, had an accumulated deficit of $141.1 million and positive working capital of $3.5 million. The Company currently anticipates incurring substantial expenditures to further its capital investment programs and the Company s cash flow from operating activities will not be sufficient to both satisfy its current obligations and meet the requirements of these capital investment programs. Recovery of capitalized costs related to potential HTL and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. Management s plans include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives. The Company intends to utilize revenue from existing operations to fund the transition of the Company to a heavy oil exploration, production and upgrading company and non-heavy oil related investments in our portfolio will be leveraged or monetized to capture value and provide maximum return for the Company. The outcome of these matters cannot be predicted with certainty at this time and therefore the Company may not be able to continue as a going concern. These consolidated financial statements do not include any adjustments to the amounts and classification of assets and liabilities that may be necessary should the Company be unable to continue as a going concern.

2. CHANGES IN ACCOUNTING POLICIES

2007 Accounting Changes

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

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

S.1530 introduces Comprehensive Income, which consists of Net Income and Other Comprehensive Income (OCI). OCI represents changes in Shareholder s Equity during a period arising from transactions and other events with non-owner sources. There was no material impact on adoption of this Section; there is no difference between the Net Loss presented in the accompanying statement of operations and accumulated deficit and the comprehensive loss.
S.3251 establishes standards for the presentation of equity and changes in equity during a reporting period. There was no material impact on adoption of this Section.

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

Financial assets

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

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

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

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

Financial liabilities

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

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

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

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

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

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

Derivative Financial Instruments

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

Derivative financial instruments are classified as held for trading and recorded on the consolidated balance sheet at fair value, either as an asset or as a liability under other current financial assets or other current financial liabilities, respectively. Changes in the fair value

of these financial instruments, or unrealized gains and losses, are recognized in the statement of operations as revenues in the period in which they occur.

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

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

There was no material impact on adoption of Section 3855.

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

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

Impact of New and Pending Canadian GAAP Accounting Standards

In early 2006, Canada s Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards (**IFRS**) over a transitional period. The Accounting Standards Board has developed and published a detailed implementation plan with an expected changeover to International Financial Reporting Standards on January 1, 2011. In addition, opening balances in accordance with IFRS will be required to be determined for the year prior to this changeover or, as in the Company s case, two years prior to the changeover for companies that present three years comparative statements. Management is in the process of reviewing the impact of this plan on its financial statements.

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

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3. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by geographical location and business segment are as follows:

	As at September 30, 2007				
	Oil and Gas				
	U.S.	China	HTL	GTL	Total
Oil and Gas Properties:					
Proved	$ 106,348	$ 114,758	$	$	$ 221,106
Unproved	4,369	17,751			22,120
	110,717	132,509			243,226
Accumulated depletion	(25,618)	(52,954)			(78,572)
Accumulated provision for impairment	(50,350)	(10,420)			(60,770)
	34,749	69,135			103,884
HTL ™ and GTL Investments:					
Feasibility studies and other deferred costs			301	5,054	5,355
Feedstock test facility			1,784		1,784
Commercial demonstration facility			9,671		9,671
Accumulated depreciation			(4,723)		(4,723)
			7,033	5,054	12,087
Furniture and equipment	526	116	108		750
Accumulated depreciation	(438)	(72)	(61)		(571)
	88	44	47		179
	$ 34,837	$ 69,179	$ 7,080	$ 5,054	$ 116,150

	As at December 31, 2006				
	Oil and Gas				
	U.S.	China	HTL	GTL	Total
Oil and Gas Properties:					
Proved	$ 102,884	$ 106,171	$	$	$ 209,055
Unproved	5,765	8,279			14,044
	108,649	114,450			223,099
Accumulated depletion	(21,249)	(39,372)			(60,621)
Accumulated provision for impairment	(50,350)	(10,420)			(60,770)
	37,050	64,658			101,708
HTL ™ and GTL Investments:					
Feasibility studies and other deferred costs			6,615	5,054	11,669

Feedstock test facility			405		405
Commercial demonstration facility			11,700		11,700
Accumulated depreciation			(3,789)		(3,789)
			14,931	5,054	19,985
Furniture and equipment	530	115	80		725
Accumulated depreciation	(414)	(56)	(30)		(500)
	116	59	50		225
	$ 37,166	$ 64,717	$ 14,981	$ 5,054	$ 121,918

In late 2004, the Company signed a memorandum of understanding with the Iraqi Ministry of Oil to evaluate a specific, large heavy oil field and its commercial development potential using Ivanhoe Energy s HTL™ Technology. Since that time, the Company has carried out a detailed analysis and has generated data regarding the applicability of its HTL ™ upgrading technology for the development of the field.

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

The agreement provides INPEX with a 45% interest in the venture, with Ivanhoe Energy retaining a 55% majority interest. Both parties will participate in the pursuit of the opportunity but Ivanhoe will lead the discussions with the Iraqi Ministry of Oil. Should the

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Company and INPEX proceed with the development and deploy Ivanhoe Energy s HTL™ Technology, certain technology fees would be payable to the Company by INPEX.

In the first quarter of 2007, the Company disposed of U.S. oil and gas property interests with proceeds totaling $1.0 million. In the first quarter of 2006, the Company disposed of U.S. oil and gas property interests with proceeds totaling $5.4 million. The sales proceeds were credited to the carrying value of its U.S. oil and gas properties as the sales did not significantly alter the depletion rate for the U.S. cost center.

The Company re-acquired a 40% working interest in the Dagang oil project in February of 2006 (See Note 12). The total purchase price was $28.3 million and has been included in China s proved properties.

Costs as at September 30, 2007 and December 31, 2006 of $22.1 million and $14.0 million, related to unproved oil and gas properties have been excluded from costs subject to depletion and depreciation. The depletion calculation includes $5.1 million and $14.7 million for future development costs associated with proven undeveloped reserves as at September 30, 2007 and December 31, 2006.

4. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

HTL™ Technology

In the merger with Ensyn Group, Inc. (**Ensyn**), the Company acquired an exclusive, irrevocable license to deploy, worldwide, the patented rapid thermal processing process (**RTP™ Process**) for petroleum applications as well as the exclusive right to deploy the RTP™ Process in all applications other than biomass. The Company s carrying value of the RTP™ Process for heavy oil upgrading (**HTL™ Technology** or **HTL™**) as at September 30, 2007 and December 31, 2006 was $92.2 million.

Syntroleum Master License

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use Syntroleum s proprietary gas-to-liquids (**GTL Technology** or **GTL**) process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. In respect of GTL projects in which both the Company and Syntroleum participate no additional license fees or royalties will be payable by the Company and Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum GTL master license as at September 30, 2007 and December 31, 2006 was $10.0 million.

These intangible assets were not amortized and their carrying values were not impaired for the three-month and nine-month periods ended September 30, 2007 and 2006.

5. NOTES PAYABLE

Notes payable consisted of the following as at:

	September 30, 2007	December 31, 2006
Non-interest bearing promissory note, due 2006 through 2009	$ 3,491	$ 5,336
Variable rate bank note, 8.36% - 8.48%, due 2008	4,500	1,500
Variable rate bank note, 9.337% due 2010	7,000	
	14,991	6,836
Less:		
Unamortized discount	(201)	(452)
Unamortized deferred financing costs	(665)	
Current maturities	(6,188)	(2,147)

		(7,054)		(2,599)
	$	7,937	$	4,237

Promissory Notes

In February 2006, the Company re-acquired the 40% working interest in the Dagang oil project not already owned by the Company. Part of the consideration was the issuance by the Company of a non-interest bearing, unsecured promissory note in the principal amount of approximately $7.4 million ($6.5 million after being discounted to net present value). The note is payable in 36 equal monthly installments commencing March 31, 2006 (See Note 12).

Bank Notes

In October 2006 the Company obtained from an international bank a $15 million Senior Secured Revolving/Term Credit Facility with an initial borrowing base of $8 million. The facility is for two years, the first 18 months in the form of a revolver and at the end of 18 months, the then outstanding amount will convert into a six-month amortizing loan. Depending on the drawn amount, interest, at the Company s option, will be either at 1.75% to 2.25%, above the bank s base rate or 2.75% to 3.25% over the London Inter-Bank Offered Rate (**LIBOR**). The loan terms include the requirement for the Company to enter into two-year commodity derivative contracts (See Note 10) covering approximately 75% of the Company s estimated production from its South Midway Property in California and Spraberry Property in West Texas. As part of reestablishing the borrowing base amount, the Company was required to enter into an additional commodity derivative contract (see Note 10). The facility is secured by a mortgage on both of these properties. The Company made an initial $1.5 million draw of this facility in October 2006 and a subsequent draw of $3.0 million in September 2007.

In September 2007 the Company obtained from an international bank a $30 million Revolving/Term Credit Facility with an initial borrowing base of $10 million. The facility is a revolving facility with a three-year term with interest payable only during the term. Interest will be three-month LIBOR plus 3.75%. The loan terms include the requirement for the Company to enter into three-year commodity derivative contracts (See Note 10) covering approximately 50% of the Company s estimated production from its Dagang field in China. The facility is secured by a pledge of collections from the Company s monthly oil sales in China and by a pledge of shares of the Company s Chinese subsidiaries. The Company made an initial $7.0 million draw of this facility in September 2007.

The scheduled maturities of the notes payable, excluding unamortized discount, as at September 30, 2007 were as follows:

2007	$ 615
2008	6,960
2009	416
2010	7,000
	$ 14,991

6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties and the HTL™ commercial demonstration facility (**CDF**). The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at September 30, 2007 was estimated at $5.1 million. These payments are expected to be made over the next 40 years; with over half of the payments to be made between 2008 and 2014. To calculate the present value of these obligations, the Company used an inflation rate of 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 6%. The changes in the Company s liability for the nine-month period ended September 30, 2007 were as follows:

Carrying balance, beginning of period	$ 1,953
Liabilities incurred	20
Liabilities transferred	(3)
Accretion expense	99
Revisions in estimated cash flows	609
	2,678
Less: current portion	748

Carrying balance, end of period	$ 1,930

7. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

Under the production-sharing contract for the Zitong block, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase 1**). The Phase 1 work program included acquiring approximately 300 miles of new seismic lines, reprocessing approximately 1,250 miles of existing seismic lines and drilling a minimum of approximately 23,000 feet. The Company completed Phase 1 with the exception of drilling approximately 13,800 feet. The first Phase 1 exploration well drilled in 2005 was suspended, having found no commercial quantities of hydrocarbons. Drilling of the second exploration well

commenced in October 2006, but it was not completed and tested by November 30, 2006, the initial deadline for completing the Phase 1 exploration program. The Company initially received a letter from PetroChina extending Phase 1 to September 30, 2007 and has
now received a letter of approval to further extend Phase 1 to December 31, 2007 to allow for an evaluation period following the final testing of the well.

In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million. Mitsubishi has the option to increase its participating interest to 20% by paying $0.4 million plus costs per percentage point prior to any discovery, or $8.0 million plus costs for an additional 10% interest after completion and testing of the first well drilled under the farm-out agreement.

The Company and Mitsubishi (the **Zitong Partners**) will await the pending test results of the second exploration well drilled during Phase 1 before making a decision whether or not to enter into the next three-year exploration phase (**Phase 2**). If the Company elects not to enter into Phase 2, it will be required to pay China National Petroleum Corporation (**CNPC**), within 30 days after its election, a cash equivalent of its share of the deficiency in the work program estimated to be $0.2 million after the drilling of the second Phase 1 well. If the Company elects not to enter Phase 2, costs related to the Zitong block in the approximate amount of $17.8 million will be required to be included in the depletable base of the China full cost pool. This may result in a ceiling test impairment related to the China full cost pool in a future period.

If the Zitong Partners elect to participate in Phase 2, they must relinquish 25% of the Zitong block acreage and complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and approximately 23,000 feet of drilling, with estimated contractual minimum expenditures for the Zitong block of $16.0 million. The Phase 2 seismic commitment was fulfilled in the Phase 1 exploration program. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production. If the Zitong Partners elect to enter into Phase 2, they must complete the minimum work program or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase.

Income Taxes

The Company s income tax filings are subject to audit by taxation authorities, which may result in the payment of income taxes and/or a decrease in its net operating losses available for carry-forward in the various jurisdictions in which the Company operates (the tax loss carry-forwards in Canada were Cdn. $43.5 million, in the U.S. $91.9 million and in China $13.6 million as at December 31, 2006). While the Company believes its tax filings have been prepared on a basis consistent with Chinese tax laws, the results of potential audits or the effect of changes in tax law cannot be ascertained at this time. In the first quarter 2007 the Company received an indication from local Chinese tax authorities as to a change in the rule under which development costs may be deducted in arriving at taxable income. Although the Company has received no formal written notification of any rule changes, we have reviewed the potential impact of such anticipated rule changes and reviewed our prior filings and the filing for the 2006 tax year and the Company s calculations indicate that there are no taxes payable for the 2006 and 2007 taxation years or for any prior periods. The Company has verbally confirmed that this position is acceptable to the tax authorities, and will continue its discussions with Chinese tax authorities to finalize its future and ongoing filing positions.

Long Term Obligation

As part of the Ensyn merger, the Company assumed an obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the HTL™ Technology for petroleum applications reach a total of $100.0 million. This obligation was recorded in the Company s consolidated balance sheet.

Other Commitments

The Company has recently contracted with Zeton Inc. (Zeton) to construct a Feedstock Test Facility (**FTF**) that has been designed to process small quantities of heavy oil. The contract is considered a lump-sum turn-key contract with scheduled payments tied to milestones. Should Zeton meet all of the remaining milestones the Company will be obligated to pay $4.9 million in addition to what has been paid to date.

As part of the Ensyn merger, the Company assumed an obligation to advance to a former affiliate of Ensyn (the **Former Ensyn Affiliate**) up to approximately $0.4 million if the Former Ensyn Affiliate cannot meet certain debt servicing ratios required under a Canadian municipal government loan agreement. The principal amount of this loan is repayable in nine equal annual installments commencing April 1, 2006 and ending April 1, 2014. The parent corporation of the Former Ensyn Affiliate has agreed to indemnify the Company for any amounts advanced to the Former Ensyn Affiliate under the loan agreement.

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The Company may provide indemnities to third parties, in the ordinary course of business, that are customary in certain commercial transactions such as purchase and sale agreements. The terms of these indemnities will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

The Company s management is of the opinion that any resulting settlements relating to potential litigation matters or indemnities would not materially affect the financial position of the Company.

8. SHARE CAPITAL

Following is a summary of the changes in share capital and stock options outstanding for the nine-month period ended September 30, 2007:

	Common Shares			Stock Options	
	Number (thousands)	Amount	Contributed Surplus	Number (thousands)	Weighted Average Exercise Price Cdn.$
Balance December 31, 2006	241,216	$ 318,725	$ 6,489	12,370	$ 2.34
Shares issued for:					
Services	427	794			
Exercise of options	1,167	298	(20)	(1,413)	$ 0.57
Options:					
Granted			1,819	1,987	$ 2.03
Expired				(1,552)	$ 3.05
Purchase warrants expired			533		
Balance September 30, 2007	242,810	$ 319,817	$ 8,821	11,392	$ 2.43

Purchase Warrants

The only change to the number of the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the nine-month period ended September 30, 2007 were the expiration of 1,000 purchase warrants in July 2007. The value of $0.5 million associated with these warrants was reclassified from Purchase Warrants to Contributed Surplus at the time of expiration.

As at September 30, 2007, the following purchase warrants were exercisable to purchase common shares of the Company until the expiry date at the price per share as indicated below:

		Purchase Warrants						
Year of Issue	Price per Special Warrant	Issued	Exercisable	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share	Value on Exercise ($U.S. 000)
			(thousands)					
2005	Cdn. $3.10	4,100	4,100	4,100	$ 2,412	(1)	Cdn.$3.50	$ 14,399
2005	U.S.$1.63	11,196	11,196	11,196	1,891	(3)	U.S.$2.50	27,990
2005	n/a	2,000	2,000	2,000	314	(4)	U.S.$2.00	4,000
2006	U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93(2)	33,516
		28,696	28,696	28,696	$ 23,422			$ 79,905

(1) In March 2007, the Company agreed that the warrants, which were to have expired on April 15, 2007, would be extended until the earlier of: (i) April 15, 2008; and (ii) thirty days following the date the closing trading price of the common shares of the Company on the Toronto Stock Exchange exceeds the exercise price of the warrants for a period of five consecutive trading days.
(2) Each common share purchase warrant originally entitled the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing. In September 2006, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.
(3) In October 2007, the Company agreed that 10,996,330 of these warrants, which were to have expired in November 2007, would be extended until the earlier of: (i) six months from their original expiry date; and (ii) thirty days following the date the closing trading price of the common shares of the Company on the Toronto Stock Exchange exceeds the exercise price of the warrants for a period of five consecutive trading days.
(4) In October 2007, the Company agreed that the warrants, which were to have expired November 15, 2007, would be extended until the earlier of: (i) May 15, 2008; and (ii) thirty days following the date the closing trading price of the common shares of the Company on the Toronto Stock Exchange exceeds the exercise price of the warrants for a period of five consecutive trading days.
The weighted average exercise price of the exercisable purchase warrants, as at September 30, 2007 was U.S. $2.78 per share.

9. SEGMENT INFORMATION

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

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

HTL™

The Company seeks to increase its oil reserves through the deployment of our HTL™ Technology. The technology is intended to be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. In addition, an HTL™ facility can yield surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the RTP™ Process provides heavy-oil producers with an alternative to natural gas that now is widely used to generate steam.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL Technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products.

Corporate

The Company s corporate office is in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate**.**

The following tables present the Company s interim segment information for the three-month and nine-month periods ended September 30, 2007 and 2006 and identifiable assets as at September 30, 2007 and December 31, 2006:

	Three-Month Period Ended September 30, 2007					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 2,870	$ 7,994	$	$	$	$ 10,864
Loss on derivative instruments	(1,433)	(720)				(2,153)
Interest income	32	12			68	112
	1,469	7,286			68	8,823
Operating costs	1,046	3,220				4,266
General and administrative	381	416			1,928	2,725
Business and technology development			2,528	303		2,831
Depletion and depreciation	1,306	4,537	196	3	2	6,044
Interest expense and financing costs	110		7		72	189
	2,843	8,173	2,731	306	2,002	16,055
Net Loss	$ (1,374)	$ (887)	$ (2,731)	$ (306)	$ (1,934)	$ (7,232)

Capital Investments	$	645	$	7,735	$	720	$		$		$	9,100

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	Nine-Month Period Ended September 30, 2007					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 8,380	$ 21,869	$	$	$	$ 30,249
Loss on derivative instruments	(2,208)	(720)				(2,928)
Interest income	93	31			224	348
	6,265	21,180			224	27,669
Operating costs	3,183	8,991				12,174
General and administrative	1,564	1,446			5,971	8,981
Business and technology development			6,680	661		7,341
Depletion and depreciation	4,402	13,591	955	8	4	18,960
Interest expense and financing costs	295	5	20		251	571
	9,444	24,033	7,655	669	6,226	48,027
Net Loss	$ (3,179)	$ (2,853)	$ (7,655)	$ (669)	$ (6,002)	$ (20,358)
Capital Investments	$ 2,438	$ 18,053	$ 2,066	$	$	$ 22,557
Identifiable Assets (As at September 30, 2007)	$ 42,328	$ 82,384	$ 99,402	$ 15,071	$ 4,029	$ 243,214
Identifiable Assets (As at December 31, 2006)	$ 42,158	$ 72,970	$ 107,186	$ 15,081	$ 11,149	$ 248,544

	Three-Month Period Ended September 30, 2006					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 3,396	$ 10,349	$	$	$	$ 13,745
Interest income	46	27			197	270
	3,442	10,376			197	14,015
Operating costs	976	3,748				4,724
General and administrative	431	359			2,131	2,921
			1,661	382		2,043

Business and technology development						
Depletion and depreciation	1,445	5,910	413	3	1	7,772
Interest expense and financing costs	60	35			116	211
Write off of deferred acquisition costs		732				732
	2,912	10,784	2,074	385	2,248	18,403
Net Income (Loss)	$ 530	$ (408)	$ (2,074)	$ (385)	$ (2,051)	$ (4,388)
Capital Investments	$ 2,929	$ 1,630	$ 393	$ 67	$	$ 5,019

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	Nine-Month Period Ended September 30, 2006					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 9,455	$ 26,930	$	$	$	$ 36,385
Interest income	112	42			424	578
	9,567	26,972			424	36,963
Operating costs	3,092	8,206				11,298
General and administrative	1,353	1,038			5,257	7,648
Business and technology development			4,008	1,151		5,159
Depletion and depreciation	3,906	17,573	3,317	8	4	24,808
Interest expense and financing costs	189	141	3		404	737
Write off of deferred acquisition costs		732				732
Provision for impairment		750				750
	8,540	28,440	7,328	1,159	5,665	51,132
Net Income (Loss)	$ 1,027	$ (1,468)	$ (7,328)	$ (1,159)	$ (5,241)	$ (14,169)
Capital Investments	$ 4,982	$ 6,292	$ 1,909	$ 439	$	$ 13,622

10. DERIVATIVE INSTRUMENTS

The Company s results of operations are sensitive mainly to fluctuations in oil and natural gas prices. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

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

For the three-month and nine-month periods ended September 30, 2007, the Company had $0.5 million and $0.2 million realized losses on these derivative transactions, and $1.7 million and $2.7 million of unrealized losses. Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

For the nine-month period ended September 30, 2006 the Company had no derivative activities.

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11. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for the three-month and nine-month periods ended September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Supplemental Cash Flow Information:				
Cash paid during the period for:				
Income taxes	**$ 1**	$	**$ 6**	$ 6
Interest	**$ 22**	$ 73	**$ 108**	$ 371
Investing and Financing activities, non-cash:				
Acquisition of oil and gas assets				
Shares issued	**$**	$	$	$ 20,000
Debt issued				6,547
Receivable applied to acquisition				1,746
	$	$	$	$ 28,293
Changes in non-cash working capital items				
Operating Activities:				
Accounts receivable	**$ (921)**	$ (1,130)	**$ (453)**	$ (2,986)
Prepaid and other current assets	**155**	26	**407**	(71)
Accounts payable and accrued liabilities	**1,081**	1,383	**234**	(543)
	315	279	**188**	(3,600)
Investing Activities				
Accounts receivable	**(5)**	(49)	**(139)**	2,163
Prepaid and other current assets	**19**	(16)	**79**	28
Accounts payable and accrued liabilities	**2,175**	(4,177)	**755**	(12,462)
Project advance from partner		(1,064)		2,186
	2,189	(5,306)	**695**	(8,085)
	$ 2,504	$ (5,027)	**$ 883**	$ (11,685)

12. MERGER AND ACQUISITIONS

The January 2004 Dagang field farm-out agreement between the Company and Richfirst Holdings Limited (**Richfirst**), provided Richfirst with the right to exchange its working interest in the Dagang field for common shares of the Company at any time prior to eighteen months after the closing of the farm-out transaction contemplated by the agreement. Richfirst elected to exchange its 40% working interest in the Dagang field and, in February 2006, the Company re-acquired Richfirst s 40% working interest for total consideration of $28.3 million consisting of $20.0 million paid by way of the issuance to Richfirst of 8,591,434 common shares of the Company, a non-interest bearing, unsecured promissory note in the principal amount approximately $7.4 million ($6.5 million after being discounted to net present value) and the forgiveness of $1.8 million of unpaid joint venture receivables. The promissory note is payable in 36 equal monthly installments commencing March 31, 2006. The Company has the right, during the three-year loan repayment period, to require Richfirst to convert the remaining unpaid balance of the promissory note into common shares of Sunwing Energy Ltd (**Sunwing"**), the Company s wholly-owned subsidiary, or another company owning all of the outstanding shares of Sunwing, subject to Sunwing or the other company having obtained a listing of its common shares on a prescribed stock exchange. The number of shares issued would be determined by dividing the then outstanding principal balance under the promissory note by the issue price of shares of the newly listed company issued in the transaction that results in the listing, less a 10% discount.

In February 2006, the Company signed a non-binding memorandum of understanding regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), a U.S. public corporation. In May 2006 the parties entered a definitive agreement for the transaction which was later terminated. As a result, the Company wrote off deferred acquisition costs previously capitalized in the amount of $0.7 million.

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13. ADDITIONAL DISCLOSURE REQUIRED UNDER U.S. 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, the details of which are as follows:

Condensed Consolidated Balance Sheets

Shareholders Equity and Oil and Gas Properties and Investments

	As at September 30, 2007					
			Shareholders Equity			
	Oil and Gas Properties and Investments	Derivative Instruments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 116,150	$ 3,175	$ 343,239	$ 8,821	$ (141,141)	$ 210,919
Adjustments for:						
Reduction in stated capital (i)			74,455		(74,455)	
Accounting for stock based compensation (ii)			(397)	(3,351)	3,748	
Fair value adjustment of derivative instruments (iii)		6,903	(8,019)	(533)	1,649	(6,903)
Ascribed value of shares issued for U.S. royalty interests, net (iv)	1,358		1,358			1,358
Provision for impairment (v)	(26,270)				(26,270)	(26,270)
Depletion adjustments due to differences in provision for impairment (vi)	8,019				8,019	8,019
HTL ™ and GTL development costs expensed, net (vii)	(5,570)				(5,570)	(5,570)
U.S. GAAP	$ 93,687	$ 10,078	$ 410,636	$ 4,937	$ (234,020)	$ 181,553

	As at December 31, 2006					
			Shareholders Equity			
	Oil and Gas Properties and Investments	Derivative Instruments	Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 121,918	$ 493	$ 342,680	$ 6,489	$ (120,783)	$ 228,386
Adjustments for:						
			74,455		(74,455)	

Reduction in stated capital (i)						
Accounting for stock based compensation (ii)			(387)	(3,361)	3,748	
Fair value adjustment of derivative instruments (iii)		6,378	(8,552)		2,174	(6,378)
Ascribed value of shares issued for U.S. royalty interests, net (iv)	1,358		1,358			1,358
Provision for impairment (v)	(26,270)				(26,270)	(26,270)
Depletion adjustments due to differences in provision for impairment (vi)	4,402				4,402	4,402
HTL ™ and GTL development costs expensed, net (vii)	(11,669)				(11,669)	(11,669)
U.S. GAAP	$ 89,739	$ 6,871	$ 409,554	$ 3,128	$ (222,853)	$ 189,829

Shareholders Equity

(i) In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.5 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.5 million as at September 30, 2007 and December 31, 2006.

(ii) For Canadian GAAP, the Company accounts for all stock options granted to employees and directors since January 1, 2002 using the fair value based method of accounting. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. For U.S. GAAP, prior to January 1, 2006 the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $3.7 million in the accumulated deficit as at September 30, 2007, and December 31, 2006, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 and expensed through December 31, 2005 under Canadian GAAP.

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This statement (**SFAS No. 123(R)**) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis the Company began recognizing stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as at January 1, 2006 and for all awards granted after January 1, 2006. There were no differences in the Company s stock based compensation expense in its financial statements for Canadian GAAP and U.S. GAAP for the three-month and nine-month periods ended September 30, 2007 and 2006.

(iii) The Company accounts for purchase warrants as equity under Canadian GAAP. As more fully described in our financial statements in Item 8 of our 2006 Annual Report filed on Form 10-K, in 2006, the accounting treatment of warrants was changed under U.S. GAAP to correct for the application of Statement of Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities (**SFAS No. 133**). Under SFAS No. 133, share purchase warrants with an exercise price denominated in a currency other than a company s functional currency are accounted for as derivative liabilities. Changes in the fair value of the warrants are required to be recognized in the statement of operations each reporting period for U.S. GAAP purposes. Under the Company s previous U.S. GAAP accounting treatment, no changes in fair value were recorded. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for U.S. GAAP purposes. Under Canadian GAAP, the fair value of the warrants on the issue date is recorded as a reduction to the proceeds from the issuance of common shares, with the offset to the warrant component of equity. The warrants are not revalued to fair value under Canadian GAAP. This GAAP difference resulted in an increase in derivative instruments of $6.9 million and $6.4 million as at September 30, 2007 and December 31, 2006, and a decrease in warrants of $8.0 million and $8.6 million as at September 30, 2007 and December 31, 2006.

Oil and Gas Properties and Investments

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

(v) As more fully described in our financial statements in Item 8 of our 2006 Annual Report filed on Form 10-K, there are differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference is in the method of performing ceiling test evaluations under the full cost method of accounting rules. In the ceiling test evaluation for U.S. GAAP purposes, the Company limits, on a country-by-country basis, the capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, to the estimated future net cash flows from proved oil and gas reserves using period end, non-escalated prices and costs, discounted to present value at 10% per annum, net of related tax effects, plus the cost of properties not being amortized and the lower of cost or fair value of unproved properties included in the costs being amortized. If capitalized costs exceed this limit, the excess is charged as a provision for impairment. Unproved properties are assessed quarterly for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to proved properties. At September 30, 2007 the Company s unproved properties were composed of $17.8 million related to Phase 1 of its Zitong block prospect, $2.2 million related to its Knights Landing property and the remaining $2.2 million for San Joaquin basin prospects. The Company expects to have finalized the pending test results of the second exploration well drilled in its Zitong block prospect by the

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fourth quarter of 2007 and conclude its final evaluation of Phase 1 of this prospect at that time. The Company plans to complete a multiple well drilling program by the middle of 2008 in the Knight s Landing property and conclude its final evaluation of this property in 2008. The majority of the San Joaquin prospects are fee property with no rental payments to maintain the Company s leases. The timing of drilling on these prospects is dependent on other working interest owners.

The Company performed the ceiling test in accordance with U.S. GAAP and determined that for the three-month and nine-months ended September 30, 2007 no impairment provision was required and no impairment provision was required under Canadian GAAP. The differences in the ceiling test impairments by period for the U.S. and China properties between U.S. and Canadian GAAP as at September 30, 2007 were as follows:

	Ceiling Test Impairments		(Increase)
	U.S. GAAP	Canadian GAAP	Decrease
U.S. Properties			
Prior to 2004	$ 34,000	$ 34,000	$
2004	15,000	16,350	1,350
2005	2,800		(2,800)
2006	7,600		(7,600)
2007			
	59,400	50,350	(9,050)
China Properties			
Prior to 2004	10,000		(10,000)
2004			
2005	1,700	5,000	3,300
2006	15,940	5,420	(10,520)
2007			
	27,640	10,420	(17,220)
	$ 87,040	$ 60,770	$ (26,270)

(vi) The differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion of $8.0 million and $4.4 million as at September 30, 2007 and December 31, 2006.

(vii) As more fully described in our financial statements in Item 8 of our 2006 Annual Report filed on Form 10-K, for Canadian GAAP, the Company capitalizes certain costs incurred for HTL™ and GTL projects subsequent to executing a memorandum of understanding to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in the investments in HTL™ and GTL assets. For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing an HTL™ or GTL definitive agreement are considered to be research and development and are expensed as incurred. As at September 30, 2007 and December 31, 2006, the Company capitalized $5.6 million and $11.7 million for Canadian GAAP, which was expensed for U.S. GAAP purposes.

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Condensed Consolidated Statements of Operations

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

	Three-Month Periods Ended September 30,			
	2007		2006	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ (7,232)	$ (0.03)	$ (4,388)	$ (0.02)
Fair value adjustment of derivative instruments (iii)	3,571	0.01	1,695	0.01
Provision for impairment (v and viii)			(3,570)	(0.01)
Depletion adjustments due to differences in provision for impairment (viii)	1,172	0.01	887	
HTL ™ and GTL development costs expensed (ix)	(62)		(46)	
U.S. GAAP	$ (2,551)	$ (0.01)	$ (5,422)	$ (0.02)
Weighted Average Number of Shares under U.S. GAAP (in thousands)		242,747		241,181

	Nine-Month Periods Ended September 30,			
	2007		2006	
	Net Loss	Net Loss Per Share	Net Loss	Net Loss Per Share
Canadian GAAP	$ (20,358)	$ (0.08)	$ (14,169)	$ (0.06)
Fair value adjustment of derivative instruments (iii)	(525)		(956)	
Provision for impairment (v and viii)			(10,020)	(0.04)
Depletion adjustments due to differences in provision for impairment (viii)	3,617	0.01	1,909	
HTL ™ and GTL development costs expensed (ix)	(180)		(931)	
Recovery of HTL ™ investments (ix)	6,279	0.02		
U.S. GAAP	$ (11,167)	$ (0.05)	$ (24,167)	$ (0.10)
Weighted Average Number of Shares under U.S. GAAP (in thousands)		241,812		233,766

(viii) As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the ceiling test evaluation under the full cost method of the accounting rules between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP has resulted in an accumulated net increase in impairment provisions on the Company s U.S. and China oil and gas properties of $26.3 million as at September 30, 2007 and December 31, 2006. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $1.1 million and $3.6 million in the net losses for the three-month and nine-month periods ended September 30, 2007 and a reduction of $0.9 million and $1.9 million in the net losses for the three-month and nine-month periods ended September 30, 2006.

(ix) As more fully described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing an HTL ™ or GTL definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the three-month and nine-month periods ended September 30, 2007 the Company expensed $0.1 million and $0.2 million and expensed nil and $0.9 million for those same periods in 2006 in excess of the Canadian GAAP write-downs during those corresponding periods.

As more fully described under Note 4, the Company and INPEX have signed an agreement to jointly pursue the opportunity to develop a heavy oil field in Iraq that Ivanhoe believes is a suitable candidate for its patented HTL ™ heavy oil upgrading technology. In the second quarter of 2007, the Company received a $9.0 million payment related to this agreement which was credited to the carrying value of its Iraq and CDF HTL ™ Investments related to this project for Canadian GAAP purposes. The prior costs for Iraq projects had previously been expensed for U.S. GAAP purposes therefore that portion of the proceeds, $6.3 million, was credited to the statement of operations for U.S. GAAP purposes. For the three-month and nine-month periods ended September 30, 2007 the

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Company recorded nil and $6.3 million as a reduction to net loss for U.S. GAAP when compared to Canadian GAAP due to the recovery of prior costs expensed for U.S. GAAP and capitalized for Canadian GAAP.

Pro Forma Effect of Merger and Acquisition

Had the acquisition of Richfirst s 40% working interest in the Dagang field been completed January 1, 2006, the U.S. GAAP pro forma revenue, net loss and net loss per share of the consolidated operations for the three-month and nine-month periods ended September 30, 2006 would have been as follows:

	Three-Months Ended September 30, 2006			**Nine-Months Ended September 30, 2006**		
	Revenue	**Net Loss**	**Net Loss Per Share**	**Revenue**	**Net Loss**	**Net Loss Per Share**
As reported	$ 14,015	$ (5,422)	$ (0.02)	$ 36,963	$ (24,167)	$ (0.10)
Pro forma adjustments				1,051	809	
	$ 14,015	$ (5,422)	$ (0.02)	$ 38,014	$ (23,358)	$ (0.10)
Weighted Average Number of Shares (in thousands)			241,181			235,371

Income Taxes

On January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (**FIN 48**), an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation requires that the Company recognize the impact of a tax position in the financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. In accordance with the provisions of FIN 48, any cumulative effect resulting from the change in accounting principle is to be recorded as an adjustment to the opening balance of deficit.

The implementation of FIN 48 did not result in any adjustment to the Company s beginning tax positions. The Company continues to fully recognize its tax benefits, which are offset by a valuation allowance to the extent that it is more likely than not that the deferred tax assets will not be realized. As at September 30, 2007 and December 31, 2006, the Company did not have any unrecognized tax benefits.

The Company files federal and provincial income tax returns in Canada. The Company s U.S. and China subsidiaries file federal, state and local income tax returns in the U.S. and China, as applicable. The Company may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the date of mailing of the original Notice of Assessment in respect of any particular taxation year. The U.S. federal statute of limitations for assessment of income tax is generally closed for the Company s tax years ending on or prior to 2002. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. There is no statute of limitations for audit of tax years in China. Tax authorities have not audited any of the Company s, or its subsidiaries , income tax returns or issued Notices of Assessment for any tax years.

The Company recognizes any interest accrued related to unrecognized tax benefits in interest expense and penalties in interest expense and financing costs. During the three-month and nine-month periods ended September 30, 2007 and 2006, there were no charges for interest or penalties.

Condensed Consolidated Statements of Cash Flow

As a result of expensing of HTL™ and GTL development costs required under U.S. GAAP and recovery of such costs, the statements of cash flows as reported would result in a cash surplus from operating activities of $1.7 million and $10.7 million for the three-month and nine-month period ended September 30, 2007 and $5.6 million and $10.4 million for the three-month and nine-month periods ended September 30, 2006. Additionally, capital investments reported under investing activities would be $9.0 million and $22.4 million for the three-month and nine-month period ended September 30, 2007 and $5.0 million and $12.7 million for the three-month and nine-month periods ended September 30, 2006.

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

In February 2007, the Financial Accounting Standards Board (**FASB**) issued Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (including an amendment of FASB Statement No. 115) (**SFAS No. 159**). The statement would create a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. This Statement is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Management is in the process of reviewing the requirements of this recent statement.

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

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
Forward-Looking Statements

With the exception of historical information, certain matters discussed in this Form 10-Q, including in this Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward looking statements that involve risks and uncertainties. Certain statements contained in this Form 10-Q, including statements which may contain words such as could , propose , should , intend , seeks to , is pursuing , expect , believe , similar expressions and statements relating to matters that are not historical facts are forward-looking statements. Forward-looking statements can also include discussions relating to future production associated with our HTL™ Technology, GTL Technology and EOR techniques. Such statements involve known and unknown risks and uncertainties which may cause our actual results, performances or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Although we believe that our expectations are based on reasonable assumptions, we can give no assurance that our goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, our ability to raise capital as and when required, the timing and extent of changes in prices for oil and gas, competition, environmental risks, drilling and operating risks, uncertainties about the estimates of reserves and the potential success of heavy-to light and gas-to-liquids technologies, the prices of goods and services, the availability of drilling rigs and other support services, legislative and government regulations, political and economic factors in countries in which we operate and implementation of our capital investment program.

The above items and their possible impact are discussed more fully in the section entitled Risk Factors in Item 1A and Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our 2006 Annual Report on Form 10-K.

The following should be read in conjunction with the Company s unaudited condensed consolidated financial statements contained herein, and the consolidated financial statements, and the Management s Discussion and Analysis of Financial Condition and Results of Operations, contained in the Form 10-K for the year ended December 31, 2006. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K.

The unaudited condensed consolidated financial statements in this Quarterly Report filed on Form 10-Q have been prepared in accordance with GAAP in Canada. The impact of significant differences between Canadian GAAP and U.S. GAAP on the unaudited condensed consolidated financial statements is disclosed in Note 13.

SPECIAL NOTE TO CANADIAN INVESTORS

The Company is a registrant under the Securities Exchange Act of 1934 and voluntarily files reports with the U.S. Securities and Exchange Commission (**SEC**) on Form 10-K, Form 10-Q and other forms used by registrants that are U.S. domestic issuers. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements. In 2004, the Canadian Securities Administrators (**CSA**) adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribes certain standards for the preparation and disclosure of reserves and related information by Canadian issuers. We have been granted certain exemptions from NI 51-101. Please refer to the *Special Note to Canadian Investors* on page 12 of our 2006 Annual Report on Form 10-K.

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

As generally used in the oil and gas business and in this throughout the Form 10-Q, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Mboe	= thousands of barrels of oil equivalent

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

When we refer to oil in **equivalents** , we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized industry standard in which one Bbl is

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equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Electronic copies of our filings with the SEC and the CSA are available, free of charge, through our web site (www.ivanhoeenergy.com) or, upon request, by contacting our investor relations department at (604) 688-8323. Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com) that contains our periodic reports and other public filings with the SEC and the CSA.

Ivanhoe Energy s Business

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

Ivanhoe Energy s proprietary, patented heavy oil upgrading technology upgrades the quality of heavy oil and bitumen by producing lighter, more valuable crude oil, along with by-product energy which can be used to generate steam or electricity. The HTL™ Technology has the potential to substantially improve the economics and transportation of heavy oil. There are significant quantities of heavy oil throughout the world that have not been developed, much of it stranded due to the lack of on-site energy, transportation issues, or poor heavy-light price differentials. In remote parts of the world, the considerable reduction in viscosity of the heavy oil through the HTL™ process will allow the oil to be transported economically over long distances.

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

Corporate Strategy

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

The global oil and gas industry is operating near capacity, driven by sharp increases in demand from developing economies and the declining availability of replacement low cost reserves. This has resulted in a significant increase in the relative price of oil and marked shifts in the demand and supply landscape. These shifts include demand moving toward China and India, while supply has shifted towards the need to develop higher cost/lower value resources, including heavy oil and bitumen.

Heavy oil developments can be segregated into two types: conventional heavy oil which flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While we focus on the heavier non-conventional heavy oil, both are playing an important role in creating opportunities for Ivanhoe.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most oil basins, including the Middle East and the Far East, as producers struggle to replace declines in light oil reserves. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world oil production has been getting heavier. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy-light price differentials have widened significantly.

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

These newer technologies, together with firm oil prices, have generated increased access to heavy oil resources, although for profitable exploitation, key challenges remain, with varied weightings, project by project: 1) the requirement for steam and electricity to help extract heavy oil, 2) the need for diluent to move the oil once it is at the surface, and 3) the wide heavy-light price differentials that the producer is faced with when the product gets to market. These challenges can lead to distressed assets, where economics are poor, or to stranded assets, where the resource cannot be economically produced and lies fallow.

Ivanhoe s Value Proposition

Ivanhoe s application of the HTL™ Technology seeks to address the three key heavy oil development challenges outlined above, and can do so at a relatively small scale.

In addition to improving oil quality, an HTL™ facility can yield surplus energy for production of the steam and electricity used in heavy oil production. The thermal energy generated by the HTL™ process can provide heavy oil producers with an alternative to increasingly volatile prices for natural gas that now is widely used to generate steam. Test yields of the low-viscosity, upgraded product are generally greater than 81% by volume, and high conversion of the heavy residual fraction is achieved. In addition to the liquid upgraded oil product, a small amount of valuable by-product gas is produced, and usable excess heat is generated from the by-product coke.

Ivanhoe s HTL™ process offers three potential advantages in that it can virtually eliminate cost exposure to natural gas and diluent, solve the transport challenge, and capture the majority of the heavy to light oil price differential for oil producers. Testing indicates that Ivanhoe s HTL™ process can accomplish this at a much smaller scale and at lower per barrel capital cost compared with established competing technologies, using readily available plant and process components. Since HTL™ facilities will be designed for installation near the wellhead, they are expected to eliminate the need for diluent and may make large, dedicated upgrading facilities unnecessary.

The business opportunities available to Ivanhoe correspond to the challenges each potential heavy oil project faces. In Canada, California, the Middle East and Asia, all three of the HTL™ advantages identified above come into play. In others, including certain identified opportunities in Latin America and some Middle East countries, the heavy oil naturally flows to the surface, but transport is the key problem.

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

Implementation Strategies

In order to capture the value that our HTL™ Technology provides, the Company is pursuing the following strategies:

1. ***Build a portfolio of major HTL™ projects.*** We will continue to deploy our personnel and our financial resources in support of our goal to capture opportunities for development projects utilizing our HTL™ Technology. We recently signed an agreement with a Western Canadian oil sands producer for a joint feasibility and testing program using our HTL™ Technology for the processing of a unique heavy oil stream from the producer s operations in the Athabasca oil sands. The application contemplated by this test program complements our main strategy of deploying our HTL™ Technology as a strategic tool to acquire and develop heavy oil reserves.

2. ***Advance the technology.*** Additional development work will continue as we advance the technology through the first commercial application and beyond. To optimize the technology development process, the Company has recently commenced design and construction of a Feedstock Test Facility (**FTF**) that has been designed to process small quantities of heavy oil and will allow us to:

   - Screen and test heavy oil and bitumen feedstocks in cost-effective quantities for current and potential partners,

   - Produce, assess and evaluate physical liquid products from partner heavy oil and bitumen feedstocks,

   - Conduct ongoing research and development in order to add to our portfolio of patents through the development and testing of improvements and optimizations, and

   - Have an HTL™ showcase that possesses all of the key elements of a commercial facility.

3. ***Enhance our financial position in anticipation of major projects.*** Implementation of large projects requires significant capital outlays. We are refining our financing plans and establishing the relationships required for the development activities that we see ahead. In the second quarter, the Company concluded an agreement with INPEX Corporation, Japan s largest oil and gas exploration and production company, to jointly pursue the

opportunity to develop a heavy oil field in Iraq. This agreement complements a number of other initiatives that the Company has underway that focus on heavy oil basins around the world.

4. ***Build internal capabilities in advance of major projects.*** The HTL™ technical team, which includes our own staff and specialized consultants, including the inventors of the technology, has been expanded by adding additional expertise in areas such as technical development, project management, heavy oil development and human resources.

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5. ***Build the relationships that we will need for the future.*** Commercialization of our technologies demands close alignment with partners, suppliers, host governments and financiers. The Company recently successfully completed a key Athabasca bitumen test run at its CDF. This test was an important step for our business development activities, as well as for the design of full-scale HTL™ facilities. This run represents the culmination of the CDF testing program carried out over the last two years. This test run was carried out pursuant to a technology development agreement entered into in August 2000 between subsidiaries of Ivanhoe Energy and ConocoPhillips Canada Resources Corp. (**ConocoPhillips Canada**). ConocoPhillips Canada provided the Company with the Athabasca bitumen. ConocoPhillips Canada has certain non-exclusive, capacity and time-specific rights to use the HTL™ Technology in Canada. The test run was witnessed by a third party engineering firm in preparation for the formalization of key investment banking relationships for the Company.

6. ***Capture value from other company assets as we complete the transition to a heavy oil focused company.*** Revenue from existing operations in California and China will be utilized to fund growth of the business. Non-heavy oil related investment opportunities in our portfolio will be leveraged to capture value and provide maximum return for the Company. In the third quarter, the Company closed a three year, $30 million Revolving/Term Credit Facility with an initial borrowing base of $10 million with an international bank. The facility is secured principally by operating cash flow from our China operations.

Executive Overview of 2007 Results

The following table sets forth certain selected consolidated data for the three-month and nine-month periods ended September 30, 2007 and 2006:

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2007	**2006**	**2007**	**2006**
Oil and gas revenue	$ 10,864	$ 13,745	$ 30,249	$ 36,385
Net loss	$ (7,232)	$ (4,388)	$ (20,358)	$ (14,169)
Net loss per share	$ (0.03)	$ (0.02)	$ (0.08)	$ (0.06)
Average production (Boe/d)	1,734	2,306	1,863	2,192
Net operating revenue per Boe	$ 41.36	$ 42.99	$ 35.53	$ 41.91
Capital investments	$ 9,100	$ 5,019	$ 22,557	$ 13,622
Cash flow from operating activities	$ 1,766	$ 5,353	$ 4,566	$ 11,055

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Financial Results Change in Net Loss

The following provides an analysis of our changes in net losses for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods for 2006:

	Three-Month Periods Ended September 30,:			Nine-Month Periods Ended September 30,:		
	2007	*Favorable (Unfavorable) Variances*	2006	2007	*Favorable (Unfavorable) Variances*	2006
Summary of Net Loss by Significant Components:						
Oil and Gas Revenues:	$ 10,864		$ 13,745	$ 30,249		$ 36,385
Production volumes		*$ (3,263)*			*$ (5,415)*	
Oil and gas prices		*382*			*(721)*	
Realized loss on derivative instruments	(423)	*(423)*		(246)	*(246)*	
Operating costs	(4,266)	*458*	(4,724)	(12,174)	*(876)*	(11,298)
General and administrative, less stock based compensation	(2,233)	*(305)*	(1,928)	(6,981)	*(1,234)*	(5,747)
Business and technology development, less stock based compensation	(2,565)	*(634)*	(1,931)	(6,728)	*(1,842)*	(4,886)
Acquisition costs		*732*	(732)		*732*	(732)
Net interest	(14)	*(98)*	84	(42)	*18*	(60)
Unrealized loss on derivative instruments	(1,730)	*(1,730)*		(2,682)	*(2,682)*	
Depletion and depreciation	(6,044)	*1,728*	(7,772)	(18,960)	*5,848*	(24,808)
Stock based compensation	(758)	*347*	(1,105)	(2,613)	*(439)*	(2,174)
Impairment of oil and gas properties					*750*	(750)
Other	(63)	*(38)*	(25)	(181)	*(82)*	(99)
Net Loss	$ (7,233)	*$ (2,844)*	$ (4,388)	$ (20,358)	*$ (6,189)*	$ (14,169)

Our net loss for the three-month period ended September 30, 2007 was $7.2 million ($0.03 per share) compared to our net loss for the same period in 2006 of $4.4 million ($0.02 per share). The increase in our net loss from 2006 to 2007 of $2.8 million is mainly due to a $2.8 million decrease in net operating revenues.

Our net loss for the nine-month period ended September 30, 2007 was $20.4 million ($0.08 per share) compared to our net loss for the same period in 2006 of $14.2 million ($0.06 per share). The increase in our net loss from 2006 to 2007 of $6.2 million is mainly due to a $7.3 million decrease in net operating revenues, a $3.1 million increase in general and administrative, business and technology development expenses net of stock based compensation, and a $2.7 million increase in unrealized loss on derivatives, partially offset by a favorable $5.8 million non-cash variance for depletion and depreciation and a favorable $0.8 million non-cash variance for impairment of oil and gas properties. Significant variances are explained in the sections that follow.

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Revenues and Operating Costs

The following is a comparison of changes in production volumes for the three-month and nine-month period ended September 30, 2007 when compared to the same periods in 2006:

	Three-Month Periods Ended September 30,			Nine-Month Periods Ended September 30,		
	Net Boe s		Percentage	Net Boe s		Percentage
	2007	2006	Change	2007	2006	Change
China:						
Dagang	111,012	147,571	-25%	342,368	414,660	-17%
Daqing	5,172	5,196	0%	16,069	17,189	-7%
	116,184	152,767	-24%	358,437	431,849	-17%
U.S.:						
South Midway	38,297	49,901	-23%	134,265	141,113	-5%
Spraberry	4,837	6,201	-22%	14,876	18,167	-18%
Others	240	956	-75%	1,092	7,376	-85%
	43,374	57,058	-24%	150,233	166,656	-10%
	159,558	209,825	-24%	508,670	598,505	-15%

Net production volumes for the three-month and nine-month periods ended September 30, 2007 decreased 24% and 15% when compared to the same periods in 2006 mainly due to decreases in production volumes in our China properties of 24% and 17%, resulting in decreased revenues of $3.3 million and $5.4 million.

Oil and gas prices increased 4% per Boe for the three-month period ended September 30, 2007 resulting in increased revenues of $0.4 million as compared to the same period in 2006. Oil and gas prices decreased 2% per Boe for the nine-month period ended September 30, 2007 resulting in decreased revenues of $0.7 million as compared to the same period in 2006. The increased revenues in the U.S. resulting from the price increase, when comparing the three-month period ended September 30, 2007 to the same period in 2006, were offset by settlements from our costless collar derivative instrument.

For the three-month and nine-month period ended September 30, 2007, operating costs, including production taxes and engineering support, increased 19% and 27% per Boe compared to the same periods in 2006, and are discussed further below.

China

Net production volumes at the Dagang field decreased 25% and 17% for the three-month and nine-month periods ended September 30, 2007 compared to the same periods in 2006. In addition to natural declines within the field, these decreases were caused by abnormal downtimes due to problems encountered with sub-surface equipment. Those decreases were slightly offset by four new development wells being put on line during the third quarter of 2007. A fifth well will be completed and put on production in the last quarter of this year. The September 30, 2007 exit production rate at Dagang was 1,830 Gross Bopd, of which 280 Gross Bopd was attributed to the four new wells.

Operating costs in China increased by $3.19 and $6.09 per Boe for the three-month and nine-month period ended September 30, 2007 when compared to the same periods in 2006. Field operating costs, including allocated Dagang field office costs, for the three-month and nine-month periods ended September 30, 2007 increased $2.18 and $4.84 per Boe. In addition to the abnormal downtimes mentioned above, which resulted in increased maintenance costs, increases in power costs, additional operator salaries and higher supervision charges in relation to reduced volumes contributed to the increase. In March 2006, the Ministry of Finance of the Peoples Republic of China (**PRC**) issued

the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business (the **Windfall Levy Measures**). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. For financial statement presentation the Windfall Levy is included in operating costs. The Windfall Levy resulted in a $0.36 and $0.69 per Boe increase for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods in 2006.
Engineering and support costs for the three and nine-month periods ended September 30, 2007 increased over the same periods in 2006 due to a higher allocation of support to production as the number of capital related projects decreased from 2006.

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U.S.

The 24% decrease in U.S. production volumes for the three-month period ended September 30, 2007 when compared to the same period in 2006 was mainly due a decline in production at South Midway resulting from steam generator downtime during the second quarter, along with certain wells taken offline to be soaked and steamed during the third quarter. In addition to the natural declines in production within our Spraberry field in West Texas a key producer was offline during the current quarter for repairs. The 10% decrease in U.S. production volumes for the nine-month period ended September 30, 2007 when compared to the same period in 2006 was mainly due to the sale of our Citrus properties in the first quarter of 2006, the natural declines in production within our Spraberry field in West Texas and the third quarter decreases mentioned above.

For the three-month and nine-month periods ended September 30, 2007, operating costs in the U.S., including production taxes and engineering and support costs, increased by $7.01 and $2.64 per Boe from the same period in 2006. Field operating costs for the three-month and nine-month periods ended September 30, 2007 increased by $5.40 and $1.23 per Boe, when compared to the same periods in prior years due to increases to maintenance costs and workovers at both South Midway and Spraberry especially in the third quarter of 2007. The third quarter increases were somewhat offset year to date due to a reduction in our steam operations as we were in the process of replacing a steam generator and finished repairing another generator during the second quarter. In addition to these increases, engineering and support costs for the three-month and nine-month periods ended September 30, 2007 increased by $1.12 and $1.38 per Boe, when compared to the same periods in prior years partially due to a higher allocation pool in 2007 when compared to 2006 in addition to a higher allocation of support to production as capital activity decreased.

* * *

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

	Three-Month Periods Ended September 30,					
		2007			2006	
	China	U.S.	Total	China	U.S.	Total
Net Production:						
Boe	116,184	43,374	159,558	152,767	57,058	209,825
Boe/day for the period	1,263	471	1,734	1,679	627	2,306
		Per Boe			Per Boe	
Oil and gas revenue	$ 68.81	$ 66.16	$ 68.09	$ 67.74	$ 59.51	$ 65.50
Field operating costs	17.20	18.06	17.43	15.02	12.66	14.38
Production tax (U.S.) and Windfall Levy (China)	9.20	1.46	7.09	8.84	0.97	6.70
Engineering and support costs	1.32	4.59	2.21	0.67	3.47	1.43
	27.72	24.11	26.73	24.53	17.10	22.51
Net operating revenue	41.09	42.05	41.36	43.21	42.41	42.99
Depletion	39.02	29.91	36.55	38.68	25.11	34.99
Net revenue from operations	$ 2.07	$ 12.14	$ 4.81	$ 4.53	$ 17.30	$ 8.00

	Nine-Month Periods Ended September 30,					
	2007			2006		
	China	**U.S.**	**Total**	**China**	**U.S.**	**Total**
Net Production:						
Boe	358,437	150,233	508,670	431,849	166,656	598,505
Boe/day for the period	1,313	550	1,863	1,582	610	2,192
		Per Boe			Per Boe	
Oil and gas revenue	$ 61.01	$ 55.78	$ 59.47	$ 62.36	$ 56.74	$ 60.79
Field operating costs	17.65	14.86	16.83	12.81	13.63	13.04
Production tax (U.S.) and Windfall Levy (China)	6.18	1.27	4.73	5.49	1.24	4.31
Engineering and support costs	1.26	5.06	2.38	0.70	3.68	1.53
	25.09	21.19	23.94	19.00	18.55	18.88
Net operating revenue	35.92	34.59	35.53	43.36	38.19	41.91
Depletion	37.89	29.08	35.29	40.69	23.21	35.82
Net revenue (loss) from operations	$ (1.97)	$ 5.51	$ 0.24	$ 2.67	$ 14.98	$ 6.09

General and Administrative

Changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods for 2006 were as follows:

	Three Months Ended Sept 30, 2007 vs. 2006	Nine Months Ended Sept 30, 2007 vs. 2006
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ (57)	$ (408)
U.S.	50	(211)
Corporate	203	(714)
	196	(1,333)
Less: stock based compensation	(501)	99
	$ (305)	$ (1,234)

General and administrative costs decreased by $0.2 million and increased by $1.3 million for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods in 2006. The decrease for the three-month period was mainly due to a decrease in stock based compensation, offset by an increase resulting from a reduction in the amount of overhead capitalized. The majority of the increases for the nine-month period comparison are salary and benefit related, including discretionary bonuses paid in 2007. In addition, as capital spending was down in the U.S. and the number of capital projects was down in China the amount of general and administrative expenses allocated to capital also decreased. These increases were offset by a decrease of $0.3 million for a one time charge in 2006 for the write off of the deferred loan costs on the convertible loan that was paid by way of the issuance of common shares in April 2006 private placement. These increases were also offset in part by a reallocation of resources to HTL ™ activities beginning in the second half of 2006.

Business and Technology Development

Changes in business and technology development expenses, before and after considering increases in non-cash stock based compensation, by segment for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods for 2006 were as follows:

	Three Months Ended Sept 30, 2007 vs. 2006	Nine Months Ended Sept 30, 2007 vs. 2006
Favorable (unfavorable) variances:		
HTL ™	$ (867)	$ (2,672)
GTL	79	490
	(788)	(2,182)
Less: stock based compensation	154	340

	$	(634)	$	(1,842)

Business and technology development expenses increased $0.8 million and $2.2 million for the three-month and nine-month periods ended September 30, 2007 compared to the same periods in 2006 as we continued to focus on business and technology development activities related to HTL ™ opportunities. The increase for the three-month period was mainly due to the addition of several key people and additional contract services as the Company develops its commercialization program for its technology. In addition to the third quarter increases noted above, the majority of the increases for the nine-month period comparison are related to the CDF. Operating expenses of the CDF to develop and identify improvements in the application of the HTL ™ Technology are a part of our business and technology development activities and contributed $1.4 million to the overall increase for the nine-month period ended September 30, 2007. This increase was in part the result of several heavy oil upgrading runs in the first and second quarters of 2007, including a key Athabasca bitumen test run. The Company will use the information derived from the Athabasca bitumen test run for the design and development of full-scale commercial projects in Western Canada. In addition, the HTL™ segment increased as a result of higher outside engineering fees, legal fees related to patents and a shift in resources from GTL and other segments.

Depletion and Depreciation

Depletion and depreciation decreased $1.7 million and $5.8 million for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods in 2006 partially due to a $0.2 million and $2.4 million decrease in depreciation of the CDF and a decrease in production and depletion rates for China offset by an increase in depletion rates in the U.S.

China

China s depletion rate increased $0.34 per Boe for the three-month period ended September 30, 2007 and decreased $2.80 per Boe for the nine-month period ended September 30, 2007 compared to the same periods in 2006. This resulted in no change and a $1.0 million decrease in depletion expense for the three-month and nine-month periods ended September 30, 2007. The decreases in the rates from year to year were mainly due to a $5.4 million ceiling test write down in the fourth quarter of 2006. During periods of increasing oil prices our share of proved reserves decreases, as fewer barrels of oil are required to recover our costs under our production-sharing contracts with CNPC. As a result, the depletion rate for the three-month periods noted above increased accordingly. Additionally, decreases in production volumes in China added to the decrease in depletion expense by $1.4 million and $3.0 million for the three-month and nine-month periods ended September 30, 2007 when compared to the same periods in 2006.

U.S.

The U.S. depletion rate increased $4.80 and $5.87 per Boe for the three-month and nine-month periods ended September 30, 2007 compared to the same periods in 2006, resulting in a $0.2 million and $0.9 million increase in depletion expense compared to these same periods in 2006. This increase was mainly due to the 2006 fourth quarter impairment of certain properties, including North Yowlumne, LAK Ranch and Catfish Creek, resulting in $4.8 million of those costs being included with our proved properties and therefore subject to depletion. In addition, the capital spending we incurred in 2007 related to facilities, versus drilling, and therefore did not correspondingly increase our reserve base.

HTL™

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

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents increased for the three-month period ended September 30, 2007 by $3.7 million compared to a $6.3 million decrease for the same period in 2006. Our net cash and cash equivalents increased for the nine-month period ended September 30, 2007 by $1.0 million compared to a $12.8 million increase for the same period in 2006.

Operating Activities

Our operating activities provided $1.8 million in cash for the three-month period ended September 30, 2007 compared to $5.4 million for the same period in 2006. Our operating activities provided $4.6 million in cash for the nine-month period ended September 30, 2007 compared to $11.1 million for the same period in 2006. The decrease in cash from operating activities for the three-month and nine-month periods ended September 30, 2007 was mainly due to a decrease in oil and gas production volumes.

Investing Activities

Our investing activities used $7.0 million in cash for the three-month period ended September 30, 2007 compared to $10.6 million for the same period in 2006. The main reason for the decrease is that we used $7.5 million more cash for investing activities in 2006 related to changes in working capital items as we were focused on the reduction of accounts payable in our China operations. This reduction in cash used was offset by an increase in capital asset expenditures of $4.1 million. This increase in capital spending was

mainly the result of increased exploration expenditures at our Zitong project of $1.8 million and increased development expenditures for new drilling at our Dagang project of $4.3 million, both in China. Overall expenditures were up slightly by $0.3 million for the HTL™ segment. Increased costs related to the commencement of construction of the FTF were offset by decreased costs related to the CDF as the majority of the modifications to that facility have been completed. These increases were offset by a $2.3 million decrease in capital spending in the U.S. segment resulting from a ten well drilling program at South Midway commencing in the third quarter of 2006 compared to no drilling in 2007. The 2007 South Midway drilling program has been deferred to the first quarter of 2008.
Our investing activities used $11.4 million in cash for the nine-month period ended September 30, 2007 compared to $17.3 million for the same period in 2006. The main reason for the decrease in cash used was an increase in cash inflows in 2007 of $9.0 million received from INPEX as payment for the Company s past costs related to its Iraq project and HTL™ Technology development costs. This increase in cash inflows was offset by a decrease in cash inflows due to the generation of $1.0 million of cash from asset sales in the U.S. in 2007, compared to $5.4 million for the same period in 2006. In addition to this overall net increase in cash inflows we used $8.8 million more cash for investing activities in 2006 related to changes in working capital items as we were focused on the reduction of accounts payable in our China operations. These increases to cash inflows were offset by an increase to our capital asset expenditures of $8.9 million. The increase in capital spending was mainly the result of increased exploration expenditures at our Zitong project of $8.0 million and increased development expenditures for new drilling at our Dagang project of $3.8 million, both in China. We drilled one exploration well in our Zitong project starting in the fourth quarter of 2006 with drilling completing in the second quarter of 2007. The final results of testing this well are expected be known in the fourth quarter of 2007. We drilled five development wells in our Dagang project starting in the second quarter of 2007, four of which were on production as at September 30, 2007. No such exploration or development wells were drilled in 2006. Capital spending related to HTL™ stayed constant as increased expenditures for the FTF were offset by decreased expenditures for the CDF. The increase in China was offset by reduced expenditures in the U.S. of $2.5 million and GTL of $0.4 million, due to the same events as discussed above.

Financing Activities

Financing activities for the three-month period ended September 30, 2007 consisted of two draws on two separate loan facilities compared to the scheduled repayment of long-term debt in that same period in 2006. One of these draws, in the amount of $7.0 million ($6.3 million net of financing costs), was from a $30 million Revolving/Term Credit Facility with an initial borrowing base of $10 million the Company obtained from an international bank in September 2007. The facility is a revolving facility with a three-year term with interest payable only during the term. The other draw, in the amount of $3.0 million, was from the Company s existing $15 million Senior Secured Revolving/Term Credit Facility with an initial borrowing base of $8 million from an international bank. This facility is for two years, ending in October 2008, the first 18 months in the form of a revolver and at the end of 18 months, the then outstanding amount will convert into a six-month amortizing loan.
Financing activities for the nine-month period ended September 30, 2007 consisted of the loan draws mentioned above and scheduled repayment of long-term debt compared to the same period in 2006 when financing activities consisted of $25.3 million private placement offset by the early retirement of $4.0 million in long-term debt.

Outlook for balance of 2007

The Company intends to utilize revenue from existing operations to fund the transition of the Company to a heavy oil exploration, production and upgrading company and grow our existing operations where appropriate to sustain operating cash flow and our financial position. In addition, the Company is actively engaged in the process of leveraging or monetizing the non-heavy oil related investments in our portfolio, including bank and similar financing, to capture value and provide maximum return for the Company. The Company currently anticipates incurring substantial expenditures to further its capital investment programs and the Company s cash flow from operating activities will not be sufficient to both satisfy its current obligations and meet the requirements of these capital investment programs. Recovery of capitalized costs related to potential HTL and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. Management s plans also include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives. The Company s agreement with INPEX Corporation, Japan s largest oil and gas exploration and production company and their payment of $9.0 million towards our past HTL™ investments is the first such alliance that we believe will advance the deployment of our HTL™ Technology and further our development activities.

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Contractual Obligations

The table below summarizes the contractual obligations that are reflected in our Unaudited Condensed Consolidated Balance Sheet as at September 30, 2007 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2007**	**2008**	**2009**	**2010**	**After 2010**
Consolidated Balance Sheets:						
Note payable current portion	6,188	553	5,635			
Long term debt	7,937		1,190	412	6,335	
Asset retirement obligation	2,678	147	601	503		1,427
Long term obligation	1,900			1,900		
Other Commitments:						
Interest payable	3,022	349	1,141	856	676	
Lease commitments	3,652	286	1,061	863	738	704
Zitong exploration commitment	188	188				
Total	$25,565	$1,523	$9,628	$4,534	$7,749	$2,131

Off Balance Sheet Arrangements

As at September 30, 2007 and December 31, 2006, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we currently 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.

Outstanding Share Data

As at October 26, 2007, there were 242,873,349 common shares of the Company issued and outstanding. Additionally, the Company had 28,696,330 share purchase warrants outstanding and exercisable to purchase 28,696,330 common shares. As at October 26, 2007, there were 12,784,610 incentive stock options outstanding to purchase the Company s common shares.

Quarterly Financial Data In Accordance With Canadian and U.S. GAAP (Unaudited)

	QUARTER ENDED							
	2007			**2006**				**2005**
	3rd Qtr	**2nd Qtr**	**1st Qtr**	**4th Qtr**	**3rd Qtr**	**2nd Qtr**	**1st Qtr**	**4th Qtr**
Total revenue	$ 8,823	$ 9,589	$ 9,257	$ 11,137	$14,015	$13,084	$ 9,864	$ 8,651
Net loss:								
Canadian GAAP	$(7,232)	$(6,579)	$(6,547)	$(11,323)	$ (4,388)	$ (4,405)	$ (5,376)	$(8,885)
U.S. GAAP	$(2,551)	$(1,211)	$(7,536)	$(18,255)	$ (5,422)	$ (2,329)	$(16,416)	$(7,545)
Net loss per share:								

Canadian GAAP	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.05)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.04)
U.S. GAAP	$ (0.01)	$	$ (0.03)	$ (0.08)	$ (0.02)	$ (0.01)	$ (0.07)	$ (0.03)

The differences in the net loss and net loss per share for the first quarter of 2006 were due mainly to the impairment charged for the China oil and gas properties for U.S. GAAP purposes of $7.2 million when compared to $0.8 million calculated for Canadian GAAP and $4.3 million additional fair value adjustment for U.S. GAAP. The differences in the net loss and net loss per share for the third quarter of 2006 were due mainly to the impairment charged for the U.S. oil and gas properties for U.S. GAAP purposes of $3.1 million when compared to nil calculated for Canadian GAAP, offset by a $1.7 million additional fair value adjustment for U.S. GAAP. The differences in the net loss and net loss per share for the fourth quarter of 2006 were due mainly to the impairment charged for U.S. GAAP purposes of $8.1 million ($4.5 million relates to the U.S. oil and gas properties and $3.6 million for the China oil and gas properties) when compared to nil calculated for Canadian GAAP. The differences in the net loss and net loss per share for the second quarter of 2007 were due mainly to the treatment of the payment by INPEX for past costs paid by the Company related to its Iraq project and HTL™ Technology development costs. Approximately $6.3 million of this payment was applied to capital balances

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for Canadian GAAP purposes and as reduction to net loss for U.S. GAAP purposes. The differences in the net loss and net loss per share for the third quarter of 2007 were mainly due to an additional $3.6 million fair value adjustment for U.S. GAAP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

No material changes since December 31, 2006.

Item 4. Controls and Procedures

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of September 30, 2007. Based upon this evaluation, management concluded that these controls and procedures were (1) designed to ensure that material information relating to the Company is made known to the Company s Chief Executive Officer and Chief Financial Officer as appropriate to allow timely decisions regarding disclosure and (2) effective, in that they provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

It should be noted that while the Company s principal executive officer and principal financial officer believe that the Company s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Company s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the period ended September 30, 2007, there were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II Other Information

Item 1. Legal Proceedings: None

Item 1A. Risk Factors:

As at September 30, 2007, there were no additional material risks and no material changes to the risk factors disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds: None

Item 3. Defaults Upon Senior Securities: None

Item 4. Submission of Matters To a Vote of Security Holders: None

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
10.15	Facility Agreement, dated September 14, 2007 between Pan-China Resources Ltd., Sunwing Energy Ltd., Sunwing Holding Corporation, Sunwing Zitong Energy Ltd., Standard Bank PLC and Standard Bank Asia Limited
31.1	Certification by the Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.
IVANHOE ENERGY INC.
By: /s/ W. Gordon Lancaster
Name: W. Gordon Lancaster
Title: Chief Financial Officer
Dated: November 2, 2007

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INDEX TO EXHIBITS

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