IVANHOE ENERGY INC
Form 10-Q
August 10, 2009

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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 June 30, 2009

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. þ Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **o** Yes **o** No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer **o**	Accelerated filer þ	Non-accelerated filer **o** (Do not check if a smaller reporting company)	Smaller reporting company **o**

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

The number of shares of the registrant s capital stock outstanding as of August 7, 2009 was 279,381,187 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)

	June 30, 2009	December 31, 2008
Assets		
Current Assets:		
Cash and cash equivalents	**$ 16,135**	$ 38,477
Accounts receivable	**5,118**	3,802
Prepaid and other current assets	**1,483**	1,487
Derivative instruments		1,459
Assets of discontinued operations	**63,436**	2,727
	86,172	47,952
Oil and gas properties and development costs, net	**144,335**	143,974
Intangible assets HTL^{TM} technology	**92,153**	92,153
Long term assets	**403**	152
Assets of discontinued operations		33,044
	$ 323,063	$ 317,275
Liabilities and Shareholders Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 7,263**	$ 9,219
Income tax payable		650
Debt current portion		412
Derivative instruments	**245**	
Asset retirement obligations current portion	**1,974**	
Liabilities of discontinued operations current portion	**7,337**	6,074
	16,819	16,355
Long term debt	**39,792**	37,855
Asset retirement obligations	**190**	1,928
Long term obligation	**1,900**	1,900
Future income tax liability	**29,600**	
Liabilities of discontinued operations		1,810
	88,301	59,848

Commitments and contingencies *(Note 7)*

Going concern and basis of presentation *(Note 1)*

Shareholders Equity:		
Share capital, issued 279,381,187 common shares	**413,857**	413,857
Purchase warrants	**18,805**	18,805
Contributed surplus	**17,849**	16,862
Convertible note	**2,086**	2,086
Accumulated deficit	**(217,835)**	(194,183)
	234,762	257,427
	$ 323,063	$ 317,275

(See accompanying notes)

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenue				
Oil revenue	**$ 6,009**	$ 11,746	**$ 11,742**	$ 22,635
Loss on derivative instruments	**(1,173)**	(15,009)	**(1,092)**	(17,691)
Interest income	**8**	14	**18**	42
	4,844	(3,249)	**10,668**	4,986
Expenses				
Operating costs	**2,444**	5,303	**5,145**	9,613
General and administrative	**3,834**	3,835	**9,714**	7,299
Business and technology development	**1,766**	1,445	**3,803**	2,919
Depletion and depreciation	**6,045**	6,431	**12,000**	13,340
Foreign exchange loss	**2,680**	197	**1,686**	321
Interest expense and financing costs	**158**	373	**335**	757
	16,927	17,584	**32,683**	34,249
Loss from continuing operations before income taxes	**(12,083)**	(20,833)	**(22,015)**	(29,263)
(Provision for) recovery of income taxes				
Current	**639**		**(1,006)**	
Future		2,286		2,286
	639	2,286	**(1,006)**	2,286
Net loss from continuing operations	**(11,444)**	(18,547)	**(23,021)**	(26,977)
Net income (loss) from discontinued operations	**66**	(3,184)	**(631)**	(3,298)
Net loss and comprehensive loss	**(11,378)**	(21,731)	**(23,652)**	(30,275)
Accumulated deficit, beginning of period	**(206,457)**	(168,534)	**(194,183)**	(159,990)
Accumulated deficit, end of period	**$ (217,835)**	$ (190,265)	**$ (217,835)**	$ (190,265)

Net loss per share

Net Loss from continuing operations, basic and diluted	**$**	**(0.04)**	$	(0.08)	**$**	**(0.08)**	$	(0.11)
Net Income (Loss) from discontinued operations, basic and diluted		**0.00**		(0.01)		**(0.00)**		(0.01)
Net loss per share, basic and diluted	**$**	**(0.04)**	$	(0.09)	**$**	**(0.08)**	$	(0.12)
Weighted average number of Shares (in thousands)								
Basic and diluted		**279,381**		245,250		**279,381**		245,063

(See accompanying notes)

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

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating Activities				
Net loss	**$ (11,378)**	$ (21,731)	**$ (23,652)**	$ (30,275)
Net (income) loss from discontinued operations	**(66)**	3,184	**631**	3,298
Items not requiring use of cash:				
Depletion and depreciation	**6,045**	6,431	**12,000**	13,340
Stock based compensation	**526**	793	**987**	1,911
Unrealized loss on derivative instruments	**1,249**	12,878	**1,704**	14,836
Unrealized foreign exchange loss	**2,620**		**1,646**	
Future income tax recovery		(2,286)		(2,286)
Other	**72**	202	**164**	317
Changes in non-cash working capital items	**(3,985)**	1,255	**(3,277)**	1,255
Net cash provided by (used in) operating activities from continuing operations	**(4,917)**	726	**(9,797)**	2,396
Net cash provided by operating activities from discontinued operations	**2,031**	1,900	**2,823**	3,247
Net cash provided by (used in) operating activities	**(2,886)**	2,626	**(6,974)**	5,643
Investing Activities				
Capital investments	**(6,692)**	(1,880)	**(11,900)**	(4,720)
Advance repayments		100		100
Other	**(153)**	(74)	**(153)**	(103)
Changes in non-cash working capital items	**35**	(1,040)	**(672)**	(2,434)
Net cash used in investing activities from continuing operations	**(6,810)**	(2,894)	**(12,725)**	(7,157)
Net cash used in investing activities from discontinued operations	**(233)**	(974)	**(586)**	(3,194)
Net cash used in investing activities	**(7,043)**	(3,868)	**(13,311)**	(10,351)
Financing Activities				
Proceeds from exercise of options and warrants		686		686
Proceeds from debt obligations, net of financing costs		4,772		4,772
Payments of debt obligations		(615)	**(416)**	(1,230)
Payments of deferred financing costs		(1,481)		(2,065)
Other	**(25)**		**(100)**	

Changes in non-cash working capital items		**(3)**		703		**(26)**		703
Net cash provided by (used in) financing activities from continuing operations		**(28)**		4,065		**(542)**		2,866
Net cash provided by financing activities from discontinued operations				700				700
Net cash provided by (used in) financing activities		**(28)**		4,765		**(542)**		3,566
Foreign Exchange Loss on Cash and Cash Equivalents Held in a Foreign Currency		**(4)**				**(35)**		
Increase (Decrease) in Cash and Cash Equivalents, for the period		**(9,961)**		3,523		**(20,862)**		(1,142)
Cash and cash equivalents, beginning of period		**28,364**		6,691		**39,265**		11,356
Cash and Cash Equivalents, end of period	**$**	**18,403**	$	10,214	**$**	**18,403**	$	10,214
Cash and cash equivalents, end of period continuing operations	**$**	**16,135**	$	8,732	**$**	**16,135**	$	8,732
Cash and cash equivalents, end of period discontinued operations	**$**	**2,268**	$	1,482	**$**	**2,268**	$	1,482

(See accompanying notes)

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Notes to the Unaudited Condensed Consolidated Financial Statements
June 30, 2009
(all tabular amounts are expressed in thousands of U.S. dollars except per share amounts)
(Unaudited)

1. GOING CONCERN AND BASIS OF PRESENTATION

Ivanhoe Energy Inc. s (the **Company** or **Ivanhoe Energy**) 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 15. The unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2008 consolidated financial statements except as discussed in Note 2. 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, 2008 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 three-month and six-month periods ended June 30, 2009 have been prepared in accordance with Canadian GAAP applicable to a going concern, which assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of operations. The Company incurred a net loss of $11.4 million for the three-month period ended June 30, 2009, and as at June 30, 2009, had an accumulated deficit of $217.8 million and positive working capital of $13.3 million (excluding assets and liabilities of discontinued operations). The Company currently anticipates incurring substantial expenditures to further its capital development programs, particularly those related to the development of an oil sands project in Alberta and the development of a heavy oil field in Ecuador. 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. The continued existence of the Company is dependent upon its ability to obtain capital to fund further development and to meet obligations to preserve its interests in these properties and to meet the obligations associated with other potential HTL projects. The Company intends to finance the future payments required for its capital projects from a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level. Public and private debt and equity markets may not be accessible now or in the foreseeable future and, as such, the Company s ability to obtain financing cannot be predicted with certainty at this time. Without access to financing, 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

2009 Accounting Changes

In February 2008, the Canadian Institute of Chartered Accountants (**CICA**) issued Handbook Section 3064, Goodwill and Intangible assets, (**S.3064**) replacing Handbook Section 3062, Goodwill and Other Intangible Assets (**S.3062**) a Handbook Section 3450, Research and Development Costs . S.3064 is applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous S.3062.

Also in February 2008, the CICA amended portions of Handbook Section 1000, Financial Statement Concepts , which the CICA concluded permitted deferral of costs that did not meet the definition of an asset. The amendments apply to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. Upon adoption of S.3064 and the amendments to Section 1000 on January 1, 2009, capitalized amounts that no longer meet the definition of an asset are expensed retrospectively.

The Company adopted the new standards on January 1, 2009 with no transitional adjustment to the condensed consolidated financial statements as a result of having adopted these standards.

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Impact of New and Pending Canadian GAAP Accounting Standards

In January 2009, the Emerging Issues Committee of the CICA (**EIC**) issued Emerging Issues Committee abstract 173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities which provides guidance on the implications of credit risk in determining the fair value of an entity s financial assets and financial liabilities. The guidance clarifies that an entity s own credit risk and the credit risk of counterparties should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments, for presentation and disclosure purposes. The conclusions of the EIC were effective from the date of issuance of the abstract and did not have any material impact on the Company s consolidated balance sheet or statement of operations, comprehensive loss and accumulated deficit. However, the Company s fair value disclosures in Note 10 incorporated this new guidance.

Also in January 2009, the Accounting Standards Board of the CICA (**AcSB**) issued Handbook Section 1582, Business Combinations (**S.1582**) replacing Handbook Section 1581, Business Combinations . The AcSB revised accounting standards in regards to business combinations with the intent of harmonizing those standards with IFRS. The revised standards require the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction, establish the acquisition date fair value as the measurement objective for all assets acquired and liabilities assumed; and require the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. These standards shall be applied prospectively to business combinations with an acquisition date after the beginning of the first annual reporting period beginning after January 1, 2011. The Company is currently reviewing the standard to determine the impact, if any, on its consolidated financial statements.

Also in January 2009, the AcSB issued Handbook Section 1601, Consolidated Financial Statements (**S.1601**) and Handbook Section 1602, Non-Controlling Interests (**S.1602**), which replace Handbook Section 1600, Consolidated Financial Statements (**S.1600**). S.1601 and S.1602 require all entities to report non-controlling (minority) interests as equity in consolidated financial statements. The standards eliminate the diversity that currently exists in accounting for transactions between an entity and non-controlling interests by requiring they be treated as equity transactions. These standards shall be applied retrospectively effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The Company is currently reviewing the standard to determine the impact, if any, on its consolidated financial statements.

In June 2009, the AcSB issued Accounting Revisions Release No. 54, Improving Disclosures About Financial Instruments Background Information and Basis for Conclusions (Amendments to Financial Instruments Disclosures, Section 3862) , which amended certain disclosure requirements related to financial instrument disclosure in response to disclosure amendments issued by the International Accounting Standards Board. This is consistent with the AcSB s strategy to adopt IFRS and to ensure the current existing disclosure requirements for financial instruments are converged to the extent possible. The new disclosure standards require disclosure of fair values based on a fair value hierarchy as well as enhanced discussion and quantitative disclosure related to liquidity risk. The amended disclosure requirements are effective for annual financial statements relating to fiscal years ending after September 30, 2009 and as such the Company will include the required disclosure in its annual financial statements for the year ending December 31, 2009.

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3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS

Capital assets categorized by segment are as follows:

	As at June 30, 2009					
	Oil and Gas				Business and Technology Development	
	Integrated		Conventional			
	Canada	Ecuador	China	Corporate		Total
Oil and Gas Properties:						
Proved	$	$	$ 144,406	$	$	$ 144,406
Unproved	87,443	2,959	4,439			94,841
	87,443	2,959	148,845			239,247
Accumulated depletion			(92,231)			(92,231)
Accumulated provision for impairment			(16,550)			(16,550)
	87,443	2,959	40,064			130,466
Development Costs:						
Feasibility studies and other deferred costs:						
HTL™					955	955
GTL					5,054	5,054
Accumulated provision for impairment					(5,054)	(5,054)
Feedstock test facility					10,280	10,280
Commercial demonstration facility					11,222	11,222
Accumulated depreciation					(9,084)	(9,084)
					13,373	13,373
Furniture and equipment	13	135	120	923	21	1,212
Accumulated depreciation	(7)	(36)	(83)	(572)	(18)	(716)
	6	99	37	351	3	496
	$ 87,449	$ 3,058	$ 40,101	$ 351	$ 13,376	$ 144,335

	As at December 31, 2008					
	Oil and Gas				Business and Technology Development	
	Integrated		Conventional			
	Canada	Ecuador	China	Corporate		Total
Oil and Gas Properties:						

Proved	$	$	$ 141,089	$	$	$ 141,089
Unproved	81,090	1,454	5,233			87,777
	81,090	1,454	146,322			228,866
Accumulated depletion			(81,717)			(81,717)
Accumulated provision for impairment			(16,550)			(16,550)
	81,090	1,454	48,055			130,599
Development Costs:						
Feasibility studies and other deferred costs:						
HTL™					801	801
GTL					5,054	5,054
Accumulated provision for impairment					(5,054)	(5,054)
Feedstock test facility					8,770	8,770
Commercial demonstration facility					11,036	11,036
Accumulated depreciation					(7,713)	(7,713)
					12,894	12,894
Furniture and equipment	20	90	120	13	406	649
Accumulated depreciation	(6)		(79)	(6)	(77)	(168)
	14	90	41	7	329	481
	$ 81,104	$ 1,544	$ 48,096	$ 7	$ 13,223	$ 143,974

In July 2009, the Company sold its U.S. operating segment (see Note 14); consequently the segment information has been revised to reflect this sale.

Costs as at June 30, 2009 of $94.8 million ($87.8 million at December 31, 2008), related to unproved oil and gas properties, have been excluded from costs subject to depletion and depreciation. Included in the depletion calculation is $1.5 million for future development costs associated with proven undeveloped reserves as at June 30, 2009 ($3.3 million at December 31, 2008).

For the three-month and six-month periods ended June 30, 2009, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities of $1.1 million and $2.0 million ($0.2 million and $0.4 million for 2008) were capitalized.

For the three-month and six-month periods ended June 30, 2009, interest on debt related to oil and gas acquisition activities of $0.5 million and $1.1 million (nil for the same periods in 2008) were capitalized.

4. INTANGIBLE ASSETS HTL™ TECHNOLOGY

The Company owns 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 June 30, 2009 and December 31, 2008 was $92.2 million. Since the Company acquired the technology, it has continued to expand its patent coverage to protect innovations to the HTL™ Technology as they are developed and to significantly extend the Company s portfolio of HTL™ intellectual property. In the United States, the Company is the assignee of one granted patent and currently has five patent applications pending. The Company also has multiple patents pending in numerous other countries. In addition, the Company owns exclusive, irrevocable licenses for patents, applications, and technology for the rapid thermal processing process for petroleum applications.

Recovery of capitalized costs related to potential HTL™ projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. This intangible asset was not amortized and its carrying value was not impaired for the three-month and six-month periods ended June 30, 2009 and 2008.

5. LONG TERM DEBT

Notes payable consisted of the following as at:

	June 30, 2009	December 31, 2008
Variable rate bank note (4.36% at June 30, 2009) due September 2010	$ 7,000	$ 7,000
Non-interest bearing promissory note, final payment February 2009		416
Convertible note (4.25% at June 30, 2009) due July 2011	34,409	32,787
	41,409	40,203
Less:		
Unamortized discount	(1,268)	(4)
Unamortized deferred financing costs	(349)	(1,932)
Current maturities		(412)
	(1,617)	(2,348)
	$ 39,792	$ 37,855

The scheduled maturities of the Company s long term debt, excluding unamortized discount and unamortized deferred financing costs, as at June 30, 2009 were as follows:

2010	$ 7,000
2011	34,409

$	41,409

6. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon the HTL™ commercial demonstration facility (**CDF**) and the HTL™ Feedstock Test Facility (**FTF**). The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at June 30, 2009 was estimated at $2.6 million. These payments are expected to be made over the next 20 years; with the majority of the payments expected to be made within one year. To calculate the present value of these obligations, the Company used an inflation rate of 2 and 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 5 and 6% for the respective periods shown below. A reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of the CDF and the FTF is as follows:

	As at June 30, 2009	As at December, 31 2008
Carrying balance, beginning of year	$ 1,928	$ 739
Liabilities incurred	185	
Accretion expense	51	76
Revisions in estimated cash flows		1,113
Carrying balance, end of period	2,164	1,928
Less: current portion	(1,974)	
Carrying balance, end of period	$ 190	$ 1,928

7. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

At December 31, 2005, the Company held a 100% working interest in a thirty-year production-sharing contract with China National Petroleum Corporation (**CNPC**) in a contract area, known as the Zitong Block, located in the northwestern portion of the Sichuan Basin. In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million.

The Company has completed the first phase of this project and in December 2007, the Company and Mitsubishi (the **Zitong Partners**) made a decision to enter into the next three-year exploration phase (**Phase 2**) of the project. By electing to participate in Phase 2 the Zitong Partners must relinquish 30%, plus or minus 5%, of the Zitong block acreage and complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and approximately 23,700 feet of drilling (including the Phase 1 shortfall), with total gross remaining estimated minimum expenditures for this program of $27.4 million. The Zitong Partners have relinquished 25% of the Block to complete the Phase I relinquishment requirement. The Phase 2 seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. Drilling is planned to commence in early 2010. The Zitong Partners must complete the minimum work program by the end of the Phase 2 period, December 31, 2010, or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production.

Long Term Obligation

As part of its acquisition of the HTL™ Technology license, 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 is recorded in the Company s consolidated balance sheet.

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. While the Company believes its tax filings do not include uncertain tax positions, except as noted below, the results of potential audits or the effect of changes in tax law cannot be ascertained at this time.

The Company has an uncertain tax position in China related to when its entitlement to take tax deductions associated with development costs commenced. In March 2007, the Company received a preliminary indication from local Chinese tax authorities as to a potential change in the rule under which development costs are deducted from taxable income effective for the 2006 tax year. The Company discussed this matter with Chinese tax authorities and subsequently filed its 2006 tax return for Sunwing s wholly-owned subsidiary Pan-China Resources Ltd. (**Pan-China**) taking a new filing position in which development costs are capitalized and amortized on a straight line basis over six years starting in the year the development costs are incurred rather than deducted in their entirety in the year incurred. This change resulted in a $50.3 million reduction in tax loss carry-forwards in 2007 with an equivalent increase in the tax basis of development costs available for application against future Chinese income. The Company has received no formal notification of this rule change; however it will continue to file tax returns under this new approach. To the extent that there is a different interpretation in the timing of the deductibility of development costs this could potentially result in an increase in the current tax provision of $1.3 million.

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The Company has an uncertain tax position related to the calculation of a gain on the consideration received from two farm-out transactions and the designation of whether the taxable gains may be subject to a withholding tax of 10% pursuant to Chinese tax law for income derived by a foreign entity. The Company is waiting for the Chinese tax authorities to reply to its request to validate in writing that its current treatment of such tax position is appropriate. To the extent that the calculation of a gain is interpreted differently and the amounts are subject to withholding tax there would be an additional current tax provision of approximately $0.7 million.

No amounts have been recorded in the financial statements related to the above mentioned uncertain tax positions as management has determined the likelihood of an unfavorable outcome to the Company to be low.

Other Commitments

From time to time the Company enters into consulting agreements whereby a success fee may be payable if and when either a definitive agreement is signed or certain other contractual milestones are met. Under the agreements, the consultant may receive cash, Company shares, stock options or some combination thereof. These fees are not considered to be material in relation to the overall capital costs and funding requirements of the future individual projects.

In July 2008, the Company completed the acquisition of Talisman Energy Canada s (**Talisman**) 100% working interests in two leases located in the Athabasca oil sands region in the Province of Alberta, Canada. In addition to the total purchase price of Cdn.$90.0 million, the Company may also be required to make a cash payment to Talisman of Cdn.$15 million if the requisite government and other approvals necessary to develop the northern border of one of the leases are obtained. No amount is recorded in the financial statements for this payment as at June 30, 2009 as the chance of occurrence can not be determined at this time.

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 AND WARRANTS

Following is a summary of the changes in shareholder s equity (excluding accumulated deficit) and stock options outstanding for the six-month period ended June 30, 2009:

	Common Shares					Stock Options	
	Number (thousands)	Amount	Purchase Warrants	Contributed Surplus	Convertible Note	Number (thousands)	Wtd. Avg Exercise Price Cdn.$
Balance December 31, 2008	279,381	$ 413,857	$ 18,805	$ 16,862	$ 2,086	11,913	$ 2.32
Options:							
Granted						550	$ 1.51
Cancelled/forfeited						(167)	$ 2.16
Compensation calculated for stock option grants				987			
Balance June 30, 2009	279,381	$ 413,857	$ 18,805	$ 17,849	$ 2,086	12,296	$ 2.29

There were no changes to the number of the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the six-month period ended June 30, 2009.

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As at June 30, 2009, 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:

Year of Issue	Price per Special Warrant	Purchase Warrants Issued	Exercisable	Common Shares Issuable (thousands)	Value ($U.S. 000)	Expiry Date	Exercise Price per Share	Cash Value on Exercise ($U.S. 000)
2006	U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93(1)	28,733
		11,400	11,400	11,400	$ 18,805			$ 28,733

(1) 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 of the transaction. In September 2006, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.

9. SEGMENT INFORMATION

The Company has four reportable business segments: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous financial statements included in its Form 10-Qs and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects in the second half of 2008, new segments are being reported to reflect how management now analyzes and manages the Company. In July 2009, the Company sold its U.S. operating segment (see Note 14); consequently the segment information has been revised to reflect this sale.

Oil and Gas

<u>*Integrated*</u>

Projects in this segment will have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of our HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment a heavy oil project in Alberta and a heavy oil project in Ecuador.

<u>*Conventional*</u>

The Company explores for, develops and produces crude oil and natural gas in China. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and its exploration activities are conducted on the Zitong block located in Sichuan Province. Prior to July 2009, (see Note 14) the Company conducted U.S. exploration, development and production activities primarily in California and Texas.

Business and Technology Development

The Company incurs various costs in the pursuit of projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**) or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the project s products, the Company assesses whether the feasibility and related costs incurred have potential future value, are likely to lead to a definitive agreement for the exploitation of proved reserves and should be capitalized.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the technologies it owns or licenses. The cost of equipment and facilities acquired, or construction costs for such purposes, are capitalized as development costs and amortized over the expected economic life of the equipment or facilities, commencing with the start up of commercial operations for which the equipment or facilities are intended.

Corporate

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

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The following tables present the Company s segment information for the three-month and six-month periods ended June 30, 2009 and 2008 and identifiable assets as at June 30, 2009 and December 31, 2008:

	Three-Month Period Ended June 30, 2009						
	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	China	U.S.			
Revenue							
Oil revenue	$	$	$ 6,009	$	$	$	$ 6,009
Loss on derivative instruments			(1,173)				(1,173)
Interest income			2			6	8
			4,838			6	4,844
Expenses							
Operating costs			2,444				2,444
General and administrative	196	459	630			2,549	3,834
Business and technology development	93				1,673		1,766
Depletion and depreciation	1	22	5,242		744	36	6,045
Foreign exchange loss	(5)		15			2,670	2,680
Interest expense and financing costs			131		26	1	158
	285	481	8,462		2,443	5,256	16,927
Loss from continuing operations before income taxes	(285)	(481)	(3,624)		(2,443)	(5,250)	(12,083)
Current recovery of income taxes			639				639
Net loss from continuing operations	(285)	(481)	(2,985)		(2,443)	(5,250)	(11,444)
Net income from continued operations				66			66
Net income (loss) and comprehensive income (loss)	$ (285)	$ (481)	$ (2,985)	$ 66	$ (2,443)	$ (5,250)	$ (11,378)

Capital Investments	$ 4,009	$ 895	$ 1,368	$	$ 420	$	$ 6,692

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	Six-Month Period Ended June 30, 2009						
	Oil and Gas				Business and Technology Development	Corporate	Total
	Integrated		Conventional				
	Canada	Ecuador	China	U.S.			
Revenue							
Oil revenue	$	$	$ 11,742	$	$	$	$ 11,742
Loss on derivative instruments			(1,092)				(1,092)
Interest income			4			14	18
			10,654			14	10,668
Expenses							
Operating costs			5,145				5,145
General and administrative	334	977	1,027			7,376	9,714
Business and technology development	387				3,416		3,803
Depletion and depreciation	2	36	10,516		1,373	73	12,000
Foreign exchange loss	(5)		36			1,655	1,686
Interest expense and financing costs			279		51	5	335
	718	1,013	17,003		4,840	9,109	32,683
Loss from continuing operations before income taxes	(718)	(1,013)	(6,349)		(4,840)	(9,095)	(22,015)
Current provision for income taxes			(997)			(9)	(1,006)
Net loss from continuing operations	(718)	(1,013)	(7,346)		(4,840)	(9,104)	(23,021)
Net loss from discontinued operations				(631)			(631)
Net loss and comprehensive loss	$ (718)	$ (1,013)	$ (7,346)	$ (631)	$ (4,840)	$ (9,104)	$ (23,652)

Capital Investments	$ 6,077	$ 1,551	$ 2,524	$	$ 1,694	$ 54	$ 11,900
Identifiable Assets:							
As at June 30, 2009	$ 87,528	$ 3,661	$ 54,417	$ 65,144	$ 105,853	$ 6,460	$ 323,063
As at December 31, 2008	$ 81,126	$ 1,766	$ 64,901	$ 37,480	$ 105,587	$ 26,415	$ 317,275

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	Three-Month Period Ended June 30, 2008						
	Oil and Gas				Business and Technology		
	Integrated		Conventional				
	Canada	Ecuador	China	U.S.	Development	Corporate	Total
Revenue							
Oil revenue	$	$	$ 11,746	$	$	$	$ 11,746
Loss on derivative instruments			(15,009)				(15,009)
Interest income			11			3	14
			(3,252)			3	(3,249)
Expenses							
Operating costs			5,303				5,303
General and administrative	469		558			2,808	3,835
Business and technology development	117				1,328		1,445
Depletion and depreciation			5,794		635	2	6,431
Foreign exchange loss			140			57	197
Interest expense and financing costs			149		23	201	373
	586		11,944		1,986	3,068	17,584
Loss from continuing operations before income taxes	(586)		(15,196)		(1,986)	(3,065)	(20,833)
Future recovery of income taxes			2,286				2,286
Net loss from continuing operations	(586)		(12,910)		(1,986)	(3,065)	(18,547)
Net loss from discontinued operations				(3,184)			(3,184)
Net loss and comprehensive loss	$ (586)	$	$ (12,910)	$ (3,184)	$ (1,986)	$ (3,065)	$ (21,731)

Capital Investments	$	$	$ 1,646	$	$ 231	$ 3	$ 1,880

	Six-Month Period Ended June 30, 2008						
	Oil and Gas				**Business and Technology Development**	**Corporate**	**Total**
	Integrated		**Conventional**				
	Canada	**Ecuador**	**China**	**U.S.**			
Revenue							
Oil revenue	$	$	$ 22,635	$	$	$	$ 22,635
Loss on derivative instruments			(17,691)				(17,691)
Interest income			25			17	42
			4,969			17	4,986
Expenses							
Operating costs			9,613				9,613
General and administrative	749	1	992			5,557	7,299
Business and technology development	148				2,771		2,919
Depletion and depreciation			12,000		1,337	3	13,340
Foreign exchange loss			271			50	321
Interest expense and financing costs			473		32	252	757
	897	1	23,349		4,140	5,862	34,249
Loss from continuing operations before income taxes	(897)	(1)	(18,380)		(4,140)	(5,845)	(29,263)
Future recovery of income taxes			2,286				2,286
Net loss from continuing operations	(897)	(1)	(16,094)		(4,140)	(5,845)	(26,977)
Net loss from discontinued operations				(3,298)			(3,298)
Net loss and comprehensive loss	$ (897)	$ (1)	$ (16,094)	$ (3,298)	$ (4,140)	$ (5,845)	$ (30,275)

Capital Investments	$	$	$ 3,771	$	$ 946	$ 3	$ 4,720

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10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below. Carrying amounts approximate fair value except for long term debt. After taking into account its own credit risk, the Company calculated the fair value of its long term debt to be $39.2 million as at June 30, 2009.

	As at June 30, 2009				
	Loans and receivables	Available-for-sale financial assets	Held-for-trading	Financial liabilities measured at amortized cost	Total carrying amount
Financial Assets:					
Cash and cash equivalents	$	$	$ 16,135	$	$ 16,135
Accounts receivable	5,118				5,118
Derivative instruments					
Financial Liabilities:					
Accounts payable and accrued liabilities				(7,263)	(7,263)
Derivative instruments			(245)		(245)
Long term debt				(39,792)	(39,792)
Long term obligation				(1,900)	(1,900)
	$ 5,118	$	$ 15,890	$ (48,955)	$ (27,947)

	As at December 31, 2008				
	Loans and receivables	Available-for-sale financial assets	Held-for-trading	Financial liabilities measured at amortized cost	Total carrying amount
Financial Assets:					
Cash and cash equivalents	$	$	$ 38,477	$	$ 38,477
Accounts receivable	3,802				3,802
Derivative instruments			1,459		1,459
Financial Liabilities:					
Accounts payable and accrued liabilities				(9,219)	(9,219)
Long term debt				(38,267)	(38,267)
Long term obligation				(1,900)	(1,900)
	$ 3,802	$	$ 39,936	$ (49,386)	$ (5,648)

Financial Risk Factors

The Company is exposed to a number of different financial risks arising from typical business exposures as well as its use of financial instruments including market risk relating to commodity prices, foreign currency exchange rates and interest rates, credit risk and liquidity risk. There have been no significant changes to the Company s exposure to risks or to management s objectives, policies and processes to manage risks from the previous year except the availability of financing is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, and the first six months of 2009, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when required or on commercially acceptable terms.

11. CAPITAL MANAGEMENT

The Company manages its capital so that the Company and its subsidiaries will be able to continue as a going concern and to create shareholder value through exploring, appraising and developing its assets including the major initiative of implementing multiple, full-scale, commercial HTL heavy oil projects in Canada, Ecuador and elsewhere internationally as business opportunities arise. There have been no significant changes in management s objectives, policies and processes to manage capital or the components of capital from the previous year.

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12. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for the three-month and six-month periods ended June 30:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Supplemental Cash Flow Information				
Cash paid during the period for				
Income taxes	$ 1,647	$	$ 1,655	$ 6
Interest	$ 64	$ 239	$ 1,195	$ 605
Changes in non-cash working capital items				
Operating Activities				
Accounts receivable	$ (697)	$ (651)	$ (1,361)	$ (1,611)
Prepaid and other current assets	(56)	59	(22)	156
Accounts payable and accrued liabilities	(946)	1,847	(1,244)	2,710
Income tax payable	(2,286)		(650)	
	(3,985)	1,255	(3,277)	1,255
Investing Activities				
Accounts receivable	9	(5)	46	32
Prepaid and other current assets	33	31	26	10
Accounts payable and accrued liabilities	(7)	(1,066)	(744)	(2,476)
	35	(1,040)	(672)	(2,434)
Financing Activities				
Accounts payable and accrued liabilities	(3)	703	(26)	703
	$ (3,953)	$ 918	$ (3,975)	$ (476)

Cash and cash equivalents at June 30, 2009 and December 31, 2008, are composed entirely of bank balances in checking accounts with excess cash in money market accounts which invest primarily in government securities with less than 90 day original maturities.

13. INCOME TAXES

In April 2009, the Chinese State Tax Administration Bureau issued, Circular [2009] No. 49 (the **Circular**) on depletion, depreciation and amortization expense by oil and gas companies. One of the changes to the existing rules included in the Circular that affects the Company was the increase of the minimum depreciation and amortization period from six years to eight years. The implementation of the new rules was retroactive to January 1, 2008. Consequently, upon reviewing the tax effect of the Circular, the Company revised its 2008 current tax payable in China to $1.7 million from the $0.7 million that was recorded in 2008. The $1.7 million tax payable was subsequently paid in May 2009.

Prior to the Company selling its U.S. operating segment in July 2009, as further described in Note 14, the Company had future tax assets arising from net operating losses carry-forwards generated by this business segment. These future income tax assets were partially offset by certain future income tax liabilities in the U.S. and by a valuation allowance. As at June 30, 2009, as a result of the sale of the business segment, the Company is no longer able to offset these tax assets and liabilities but is required to present these future income tax assets as assets from discontinued operations and a future income tax liability both in the amount of $29.6 million in the accompanying balance sheet.

14. SUBSEQUENT EVENT AND DISCONTINUED OPERATIONS

In June of 2009, management commenced a process to sell all of the Company s United States oil and gas exploration and production operations. On July 17, 2009 the Company completed the sale of its wholly-owned subsidiary Ivanhoe Energy (USA) Inc. for a purchase price of $39.2 million. The purchaser has acquired all of the Company s oil and gas exploration and production operations in California and Texas and additional exploration acreage in California. An escrow deposit in the amount of $2.0 million has been set aside from the sales proceeds and will be available to the purchaser for a period of one year to satisfy any indemnification obligations of the Company. The Company used approximately $5.2 million of the sales proceeds to repay an outstanding loan to a third party financial institution holding a security interest in the subsidiary company s assets. The Company intends to use the balance of the sales proceeds for the ongoing development of its heavy oil projects in Canada and Ecuador and for general corporate purposes.

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The operating results for this discontinued operation prior to sale for the periods noted were as follows:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenue				
Oil and gas revenue	**$ 2,933**	$ 6,232	**$ 4,899**	$ 10,387
Gain (loss) on derivative instruments	**3**	(5,778)	**189**	(7,042)
Interest income	**5**	22	**8**	65
	2,941	476	**5,096**	3,410
Expenses				
Operating costs	**941**	1,311	**1,968**	2,393
General and administrative	**63**	520	**130**	882
Depletion and depreciation	**1,792**	1,698	**3,469**	3,154
Interest expense and financing costs	**79**	131	**160**	279
	2,875	3,660	**5,727**	6,708
Net Income (Loss)	**$ 66**	$ (3,184)	**$ (631)**	$ (3,298)

The carrying amounts of the major classes of assets and liabilities for this discontinued operation were as follows:

	June 30, 2009	December 31, 2008
Assets		
Current Assets:		
Cash and cash equivalents	**$ 2,268**	$ 787
Accounts receivable	**1,561**	1,068
Prepaid and other current assets	**111**	172
Derivative instruments		700
	3,940	2,727
Oil and gas properties and equipment, net	**29,479**	32,577
Future income tax assets	**29,600**	
Long term assets	**417**	467
	$ 63,436	$ 35,771
Liabilities		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 278**	$ 874
Debt current portion	**5,200**	5,200

		5,478		6,074
Asset retirement obligations		**1,859**		1,810
	$	**7,337**	$	7,884

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15. 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

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

	As at June 30, 2009				**As at December 31, 2008**			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Assets								
Current Assets:								
Cash and cash equivalents	$ 16,135	$		$ 16,135	$ 38,477	$		$ 38,477
Accounts receivable	5,118			5,118	3,802			3,802
Prepaid and other current assets	1,483			1,483	1,487			1,487
Derivative instruments					1,459			1,459
Assets of discontinued operations	63,436	(22,642)	(xii)	40,794	2,727			2,727
Total Current Assets	86,172	(22,642)		63,530	47,952			47,952
Oil and gas properties and development costs, net	144,335	(38,500)	(v)	120,411	143,974	(38,500)	(v)	114,385
		16,283	(vi)			9,929	(vi)	
		(1,169)	(vii)			(1,018)	(vii)	
		(538)	(viii)					
Intangible assets technology	92,153			92,153	92,153			92,153
Long term assets	403	349	(xi)	752	152	451	(xi)	603
Assets of discontinued operations					33,044	(24,890)	(xii)	8,154
Total Assets	$ 323,063	$ (46,217)		$ 276,846	$ 317,275	$ (54,028)		$ 263,247

Liabilities and Shareholders Equity

Current Liabilities:								
Accounts payable and accrued liabilities	$ 7,263	$		$ 7,263	$ 9,219	$		$ 9,219
Income tax payable					650			650
Debt current portion					412			412
Derivative instruments	245	3,726	(iii)	3,971		1,121	(iii)	1,121
Asset retirement obligation current portion	1,974			1,974				
Liabilities of discontinued operations current portion	7,337			7,337	6,074			6,074
Total Current Liabilities	16,819	3,726		20,545	16,355	1,121		17,476
Long term debt	39,792	349	(xi)	41,409	37,855	451	(xi)	40,392
		1,548	(viii)			2,086	(viii)	
		(280)	(viii)					
Asset retirement obligations	190			190	1,928			1,928
Long term obligation	1,900			1,900	1,900			1,900
Future income tax liability	29,600			29,600				
Liabilities of discontinued operations					1,810			1,810
Total Liabilities	88,301	5,343		93,644	59,848	3,658		63,506
Shareholders Equity:								
Share capital	413,857	74,455	(i)	502,372	413,857	74,455	(i)	502,372
		(498)	(ii)			(498)	(ii)	
		1,358	(iv)			1,358	(iv)	
		13,200	(iii)			13,200	(iii)	
Purchase warrants	18,805	(18,805)	(iii)		18,805	(18,805)	(iii)	
Contributed surplus	17,849	(3,250)	(ii)	11,652	16,862	(3,250)	(ii)	10,665
		(2,947)	(iii)			(2,947)	(iii)	
Convertible note	2,086	(2,086)	(viii)		2,086	(2,086)	(viii)	
Accumulated deficit	(217,835)	(112,987)		(330,822)	(194,183)	(119,113)		(313,296)

Total Shareholders Equity	234,762	(51,560)	183,202	257,427	(57,686)	199,741
Total Liabilities and Shareholders Equity	$ 323,063	$ (46,217)	$ 276,846	$ 317,275	$ (54,028)	$ 263,247

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.

(ii) Under 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. Under U.S. GAAP, prior to January 1, 2006 the Company applied Accounting Principles Board (**APB**) Opinion No. 25, as interpreted by the Financial Accounting Standards Board (**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. Beginning January 1, 2006 the Company applied the revision to the Statement of Financial Accounting Standards (**SFAS**) No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . The Company elected to implement this statement on a modified prospective basis starting in the first quarter of 2006 whereby 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 are no significant differences between the accounting for stock options under Canadian GAAP and U.S. GAAP subsequent to January 1, 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 2008 Annual Report filed on Form 10-K, the accounting treatment of warrants under U.S. GAAP reflects the application of SFAS 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. 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.

(iv) Under U.S. GAAP, the aggregate value attributed to the acquisition of 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.

Oil and Gas Properties and Development Costs

(v) There are certain differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference 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 depletion, depreciation and amortization and deferred income taxes, to (a) 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, plus (b) the cost of properties not being amortized (e.g. major development projects) and (c) the lower of cost or fair value of unproved properties included in the costs being amortized less (d) income tax effects related to the difference between the book and tax basis of the properties referred to in (b) and (c) above. If capitalized costs exceed this limit, the excess is charged as a provision for impairment. Unproved properties and major development projects are assessed on a quarterly basis for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to the carrying value of proved oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for the six-month period ended June 30, 2009 no impairment provision was required and no impairment provision was required under Canadian GAAP. The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP were $38.5 million at June 30, 2009 and December 31, 2008.

(vi) The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion.

(vii) As more fully described in our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under Canadian GAAP, the Company capitalizes certain development costs incurred for 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 development costs. Under U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a definitive agreement are considered to be research and development and are expensed as incurred.

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(viii) As more fully described in Note 5 of our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under Canadian GAAP we were required to bifurcate the value of a convertible note, allocating a portion to long term debt and a portion to equity. Under U.S. GAAP, the convertible debt securities in their entirety are classified as debt. Under Canadian GAAP this discount accretion was capitalized. To reconcile to U.S. GAAP the entire $2.1 million recorded in equity is reversed as well as the unamortized discount of $1.5 million and the accreted discount that was capitalized in the amount of $0.5 million. In addition, because the convertible note is not denominated in U.S. currency the remeasurement of the different carrying value for U.S. GAAP results in an increase to net income. The foreign exchange gain of $0.3 million is shown as a separate amount in the U.S. GAAP reconciliation of the Company s balance sheet shown above and is adjusted to the Foreign Exchange Loss line item in the U.S. GAAP reconciliation of the statement of operations below.

Deferred Financing Costs

(xi) As more fully described in our financial statements in Item 8 of our 2008 Annual Report filed on Form 10-K, under Canadian GAAP the Company accounts for deferred financing costs, or transaction costs, as a reduction from the related liability and accounted for using the effective interest method. Under U.S. GAAP purposes, these costs are classified as other assets and amortized over the expected term of the financial liability.

Discontinued Operations

(xii) The $22.6 million adjustment includes the accumulation of adjustments related to discontinued operations. These adjustments increase and decrease the Canadian GAAP amounts as follows: a $1.4 million increase that is attributed to the acquisition of royalty rights during 2000 and 1999 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, a decrease of $29.4 million in oil and gas properties and development costs as more fully described in note (v) and an increase of $5.4 million in impairment differences as more fully described in note (vi). As at December 31, 2008, the $24.9 million adjustment related to discontinued operations also included the $1.4 million increase for the acquired royalty rights and the $29.4 million decrease in oil and gas properties and development costs described above. Additionally, a $3.1 million increase due to impairment differences as more fully described in note (vi) is also included.

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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 Months Ended June 30, 2009				**Three Months Ended June 30, 2008**			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Revenue								
Oil revenue	$ 6,009	$		$ 6,009	$ 11,746	$		$ 11,746
Loss on derivative instruments	(1,173)	(564)	(iii)	(1,737)	(15,009)	(12,204)	(iii)	(27,213)
Interest income	8			8	14			14
Total Revenue	4,844	(564)		4,280	(3,249)	(12,204)		(15,453)
Expenses								
Operating costs	2,444			2,444	5,303			5,303
General and administrative	3,834			3,834	3,835			3,835
Business and technology development	1,766			1,766	1,445			1,445
Depletion and depreciation	6,045	(3,140)	(ix)	2,905	6,431	(678)	(ix)	5,753
Foreign exchange loss	2,680	112	(viii)	2,792	197			197
Interest expense and financing costs	158			158	373			373
Provision for impairment of HTL™ development costs		5	(x)	5		128	(x)	128
Total Expenses	16,927	(3,023)		13,904	17,584	(550)		17,034
Loss from continuing operations before income taxes	(12,083)	2,459		(9,624)	(20,833)	(11,654)		(32,487)
(Provision for) recovery of income taxes								
Current	639			639				
Future					2,286			2,286
	639			639	2,286			2,286
Net loss from continuing operations	(11,444)	2,459		(8,985)	(18,547)	(11,654)		(30,201)
Net income (loss) from discontinued operations	66	1,085	(xii)	1,151	(3,184)	404	(xii)	(2,780)
Net Loss and Comprehensive Loss	(11,378)	3,544		(7,834)	(21,731)	(11,250)		(32,981)

Accumulated Deficit, beginning of period	(206,457)	(116,531)	(322,988)	(168,534)	(92,206)	(260,740)
Accumulated Deficit, end of period	$ (217,835)	$ (112,987)	$ (330,822)	$ (190,265)	$ (103,456)	$ (293,721)
Net Loss per share						
Net Loss from continuing operations, basic and diluted	**$ (0.04)**	**$ 0.01**	**$ (0.03)**	**$ (0.08)**	**$ (0.04)**	**$ (0.12)**
Net Income (Loss) from discontinued operations, basic and diluted	**0.00**	**0.00**	**0.00**	**(0.01)**	**0.00**	**(0.01)**
Net Loss per share, basic and diluted	**$ (0.04)**	**$ 0.01**	**$ (0.03)**	**$ (0.09)**	**$ (0.04)**	**$ (0.13)**
Weighted Average Number of shares (in thousands)						
Basic and Diluted	279,381		279,381	245,250		245,250

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	Six Months Ended June 30, 2009				Six Months Ended June 30, 2008			
	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP	Canadian GAAP	Increase (Decrease)	Notes	U.S. GAAP
Revenue								
Oil revenue	$ 11,742	$		$ 11,742	$ 22,635	$		$ 22,635
Loss on derivative instruments	(1,092)	(2,605)	(iii)	(3,697)	(17,691)	(15,371)	(iii)	(33,062)
Interest income	18			18	42			42
Total Revenue	10,668	(2,605)		8,063	4,986	(15,371)		(10,385)
Expenses								
Operating costs	5,145			5,145	9,613			9,613
General and administrative	9,714			9,714	7,299			7,299
Business and technology development	3,803			3,803	2,919			2,919
Depletion and depreciation	12,000	(6,354)	(ix)	5,646	13,340	(1,556)	(ix)	11,784
Foreign exchange loss	1,686	(280)	(viii)	1,406	321			321
Interest expense and financing costs	335			335	757			757
Provision for impairment of HTL™ development costs		151	(x)	151		137	(x)	137
Total Expenses	32,683	(6,483)		26,200	34,249	(1,419)		32,830
Loss from continuing operations before income taxes	(22,015)	3,878		(18,137)	(29,263)	(13,952)		(43,215)
(Provision for) recovery of income taxes								
Current	(1,006)			(1,006)				
Future					2,286			2,286
	(1,006)			(1,006)	2,286			2,286
Net loss from continuing operations	(23,021)	3,878		(19,143)	(26,977)	(13,952)		(40,929)
Net income (loss) from discontinued operations	(631)	2,248	(xii)	1,617	(3,298)	751	(xii)	(2,547)
Net Loss and Comprehensive Loss	(23,652)	6,126		(17,526)	(30,275)	(13,201)		(43,476)
Accumulated Deficit, beginning of year	(194,183)	(119,113)		(313,296)	(159,990)	(90,255)		(250,245)

Accumulated Deficit, end of period	$ (217,835)	$ (112,987)	$ (330,822)	$ (190,265)	$ (103,456)	$ (293,721)
Net Loss per share						
Net Loss from continuing operations, basic and diluted	**$ (0.08)**	**$ 0.01**	**$ (0.07)**	**$ (0.11)**	**$ (0.06)**	**$ (0.17)**
Net Income (Loss) from discontinued operations, basic and diluted	**(0.00)**	**0.01**	**0.01**	**(0.01)**	**0.00**	**(0.01)**
Net Loss per share, basic and diluted	**$ (0.08)**	**$ 0.02**	**$ (0.06)**	**$ (0.12)**	**$ (0.06)**	**$ (0.18)**
Weighted Average Number of shares (in thousands)						
Basic and Diluted	279,381		279,381	245,063		245,063

(ix) As discussed under Oil and Gas Properties and Development Costs in this note, there is a difference between U.S. and Canadian GAAP in performing the ceiling test evaluation under the full cost method of the accounting rules. 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. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction in the net loss for the three-month and six-month periods ended June 30, 2009 and 2008.

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(x) As more fully described under Oil and Gas Properties and Development Costs in this note, under Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. Under U.S. GAAP, such costs are considered to be research and development and are expensed as incurred.

Condensed Consolidated Statement of Cash Flow

There would be no material difference in cash flow presentation between Canadian and U.S. GAAP for the three-month and six-month periods ended June 30, 2009 and 2008.

Additional U.S. GAAP Disclosures

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are described below:

Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

As required by SFAS No. 157 when the inputs used to measure fair value fall within different levels of the hierarchy, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measure in its entirety.

The following table presents the Company s fair value hierarchy for those assets and liabilities measured at fair value on a recurring basis as of June 30, 2009

	As at June 30, 2009			
	Level 1	Level 2	Level 3	Total
Derivative instruments liabilities	$ 3,726	$ 245	$	$ 3,971

The fair value measurement of derivative instruments liabilities related to the Company s costless collars are considered Level 2 and the fair value measurement of derivative instruments liabilities related to its purchase warrants denominated in Cdn.$ are considered Level 1.

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

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (the **Codification**), which officially became the single source of authoritative U.S. GAAP (other than guidance issued by the U.S Securities and Exchange Commission), superseding existing FASB, American Institute of Certified Public Accountants (AICPA), Emerging Issues Task Force (EITF), and related literature. As of the July 1, 2009 effective date, only one level of authoritative U.S. GAAP exists. All other literature is considered non-authoritative. The Codification does not change U.S. GAAP; instead, it introduces a new structure that is organized in an easily accessible, user-friendly online research system. The Codification did not have an impact on the Company s consolidated financial statements.

Also in June 2009, the FASB issued SFAS No. 167, Amendments to FAS 46R (**SFAS 167**), which improves financial reporting by enterprises involved with variable interest entities. SFAS 167 replaces the quantitative-based risks and rewards calculation for determining which enterprise, if any, has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity that most significantly impact the entity s economic performance and: (1) the obligation to absorb losses of the entity; or, (2) the right to receive benefits from the entity. SFAS 167 is effective as of the beginning of the first annual reporting period that begins after November 15, 2009, and shall be applied prospectively. The Company is currently reviewing the impact, if any, on the Company s consolidated financial statements.

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Also in June 2009, the FASB issued SFAS No. 166, Accounting for Transfers of Financial Assets, an Amendment to FAS 140 , which addresses practices that have developed since the issuance of FASB s SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities (**SFAS 140**), that are not consistent with the original intent and key requirements of SFAS 140. The issuance of SFAS 140 has also increased the concerns of financial statement users that many of the financial assets (and related obligations) that have been derecognized should continue to be reported in the financial statements of transferors. The Company is currently reviewing the impact, if any, on the Company s consolidated financial statements.

In May 2009 the FASB issued SFAS No. 165, Subsequent Events , which establishes the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date, that is, whether that date represents the date the financial statements were issued or were available to be issued. The adoption of SFAS 165 did not have a material impact on our consolidated financial statements. Management has evaluated subsequent events from the balance sheet date through August 7, 2009, the date the financial statements were issued and were available to be issued.

In April 2009, the FASB issued FSP FAS 157-4, Determining Fair Value when the Volume and Level of Activity for the Asset or Liability have Significantly Decreased and Identifying Transactions that are not Orderly (**FSP 157-4**), which was effective for quarterly periods beginning April 1, 2009. FSP 157-4 affirms that the objective of fair value when the market for an asset is not active is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date under current market conditions. FSP 157-4 provides guidance for estimating fair value when the volume and level of market activity for an asset or liability have significantly decreased and determining whether a transaction was orderly. FSP 157-4 applies to all fair value measurements when appropriate. The implementation of FSP FAS 157-4 did not have a material impact on the Company s consolidated financial statements.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (**FSP 107-1**), which was effective for quarterly periods ending after June 15, 2009. FSP 107-1 requires an entity to provide the annual disclosures required by SFAS No. 107, Disclosures about Fair Value of Financial Instruments, in its interim financial statements. The implementation of FSP FAS 107-1 and APB 28-1 did not have a material impact on the Company s consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities . The new standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. It is effective beginning January 1, 2009. Management has complied with the disclosure requirements of this recent statement below.

Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility as well as being a requirement of the Company s lenders.

The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of up to 14,700 Bbls per month of the Company s 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 minimize variability in its cash flow from the sale of up to 18,000 Bbls per month of the Company s 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 WTI as the index traded on the NYMEX. All of the above contacts were put in place as part of the Company s bank loan facilities.

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Results of these derivative transactions for the three-month and six-month periods ended June 30, 2009 and 2008:

	Three Months Ended June 30,	
	2009	2008
Realized gains (losses) on derivative transactions	$ 76	$ (2,131)
Unrealized losses on derivative transactions	(1,249)	(12,878)
	$ (1,173)	$ (15,009)

	Six Months Ended June 30,	
	2009	2008
Realized gains (losses) on derivative transactions	$ 612	$ (2,855)
Unrealized losses on derivative transactions	(1,704)	(14,836)
	$ (1,092)	$ (17,691)

Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

On June 30, 2009, the Company s open positions on the derivative assets referred to above had a fair value of $0.2 million. The fair value change assumes volatility based on prevailing market parameters at June 30, 2009.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements . The standard requires all entities to report noncontrolling (minority) interests as equity in consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. This statement shall be applied prospectively. The implementation of SFAS No. 160, effective January 1, 2009, did not have a material impact on the Company s consolidated financial statements.

In February 2008, the FASB issued FASB Staff Position No. FAS 157-2, Effective Date of FASB Statement No. 157 (**FSP FAS 157-2**). FSP FAS 157-2 amends SFAS No. 157 to delay the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis. The implementation of FSP FAS 157-2, effective January 1, 2009, did not have a material impact on the Company s consolidated financial statements.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009. Management is still evaluating the impact of these changes on its financial statements.

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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 anticipate , could , propose , should , intend , seeks to , is pursuing , expec and 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 Ivanhoe Energy Ecuador s agreement with Petroecuador and Petroproduccion to develop Block 20 in Ecuador, Ivanhoe Energy s ability to obtain the financing to pay the principal and interest on the notes delivered by Ivanhoe Energy to Talisman as partial consideration for Talisman s interest in two oil sands leases and obtain the financing necessary to fund the Ecuador project, Ivanhoe Energy s plan to establish integrated HTL™ heavy oil projects on Talisman Lease 10 and Ecuador Block 20, the anticipated production capacity of the proposed HTL™ plants, the anticipated quantities of recoverable barrels of bitumen and other statements which are not historical facts and to future production associated with the HTL™ Technology and Enhanced Oil Recovery (EOR) techniques. Such statements involve known and unknown risks and uncertainties which may cause the 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 the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its 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, the 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 the Company operates and implementation of its 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 the Company s 2008 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, 2008. 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 15.

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, the Company s reserves estimates and securities regulatory disclosures generally follow SEC requirements. In 2004 and amended in 2008, 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. The Company has been granted certain exemptions from NI 51-101. Please refer to the *Special Note to Canadian Investors* on page 9 of the 2008 Annual Report on Form 10-K.

THE DISCUSSION AND ANALYSIS OF THE COMPANY S OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON NET OF WORKING INTEREST 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 throughout this Form 10-Q, the following terms have the following meanings:

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

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

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

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 using advanced technologies, including its HTL™ Technology. In mid-2008, the Company acquired two leases located in the heart of the Athabasca oil sands region in Alberta, Canada and in October 2008 the Company signed a contract with Petroproduccion and Petroecuador for the appraisal and development of a heavy oil property in Ecuador. It is anticipated that these sites will provide for the first commercial applications of the Company s HTL Technology in major, integrated heavy oil projects (see Implementation Strategy below). In addition, the Company seeks to selectively expand its reserve base and production through conventional exploration and production of oil and gas.

Core operations are in Canada, the United States, Ecuador and China with business development opportunities worldwide.

The Company has established a number of geographically focused entities. Ivanhoe Energy Inc. will pursue HTL™ opportunities in the Athabasca oil sands of Western Canada and will hold and manage the core HTL™ Technology as well as shares in geographically-focused subsidiaries. One subsidiary exclusively focused on business opportunities in Latin America signed a contract for the appraisal and development of a heavy oil property in Ecuador and another has been established to undertake activities in the Middle East and North Africa. These companies complement Sunwing Energy Ltd., the Company s existing, wholly-owned subsidiary established for activities in China and Southeast Asia. Ivanhoe Energy owns 100% of each of these subsidiaries, although its ownership interest will be diluted as they develop their respective businesses and raise equity capital independently.

We believe this structure will allow the development and financing of multiple HTL™ projects around the world, while minimizing dilution of the Company s existing shareholders at the parent level. In addition, the alignment with principal energy-producing regions will help to facilitate financing from region-specific strategic investors, some of which already have been identified, and also will enhance flexibility in accessing global capital markets.

The Company s four reportable business segments are: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous Form 10-Q Quarterly Reports and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects in the second half of 2008, new segments are being reported to reflect how management analyzes and manages the Company.

Oil and Gas

Integrated

Projects in this segment have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment - a heavy oil project in Alberta and a heavy oil project in Ecuador.

Conventional

The Company explores for, develops and produces crude oil and natural gas in China where the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and its exploration activities are conducted on the Zitong block located in Sichuan Province.

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Business and Technology Development

The Company incurs various costs in the pursuit of projects throughout the world. Such costs incurred prior to signing a MOU or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses whether the feasibility and related costs incurred have potential future value, are likely to lead to a definitive agreement for the exploitation of proved reserves and should be capitalized.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the technologies it owns or licenses. The cost of equipment and facilities acquired, or construction costs for such purposes, are capitalized as development costs and amortized over the expected economic life of the equipment or facilities, commencing with the start up of commercial operations for which the equipment or facilities are intended.

Corporate

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and related corporate activities.

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

We were incorporated pursuant to the laws of the Yukon Territory of Canada, on February 21, 1995 under the name 888 China Holdings Limited. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

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

Corporate Strategy

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

The global oil and gas industry is being impacted by the declining availability of replacement low-cost reserves. This has resulted in volatility in oil markets and marked shifts in the demand and supply landscape. Although there has been a great deal of volatility in the price of oil and significant recent price declines, we believe that long term demand and the natural decline of conventional oil production will see the development of higher cost resources, including heavy oil.

Heavy oil developments can be segregated into two types: conventional heavy oil that flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While the Company focuses on the non-conventional heavy oil, both play an important role in Ivanhoe Energy s corporate strategy.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most other oil basins, including the Middle East and Asia, as producers struggle to replace declines in light oil reserves. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world heavy oil production has become increasingly more common. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity and are restricted to conventional technologies that require very large scale and have high per-barrel costs.

With regard to non-conventional heavy oil and bitumen, the increased interest and activity has been impacted by various key advances in technology, including improved remote sensing, horizontal drilling, and new thermal techniques. This has enabled producers to more effectively access the extensive, heavy oil resources around the world. While these newer technologies have generated increased access to heavy oil resources, profitable exploitation requires key challenges to be addressed, including: 1) the requirement for steam and electricity to help extract heavy oil, 2) the need for diluent to move the oil once it is at the surface, 3) the wide heavy versus light oil price differentials that the producer is faced with when the product gets to market, and 4) conventional upgrading technologies typically require very large scale, high capital cost facilities. These challenges can lead to distressed assets, where economics are poor, or to stranded assets, where the resource cannot be economically produced and lies fallow.

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Ivanhoe s Value Proposition

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

Ivanhoe Energy s HTL Technology involves a partial upgrading process that is designed to operate in facilities as small as 10,000 to 30,000 barrels per day. This is substantially smaller than the minimum economic scale for conventional stand-alone upgraders such as delayed cokers, which typically operate at scales of over 100,000 barrels per day. The Company s HTL Technology is based on carbon rejection, a tried and tested concept in heavy oil processing. The key advantage of HTL is that it is a very fast process, as processing times are typically under a few seconds. In addition, the process does not require hydrogen, catalysts or significant pressure. This results in smaller, less costly facilities than conventional upgrading. The Company s HTL Technology has the added advantage of converting the byproducts from the upgrading process into onsite energy, rather than generating large volumes of low value coke.

The HTL process provides four key benefits to the producer:

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

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

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

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

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

The economics of any given 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 Energy value proposition.

Implementation Strategy

We are an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and we believe that we have a competitive advantage because of our patented technology. In addition, because we have experienced thermal recovery teams in Bakersfield and Calgary, we are in a position to add value and leverage our technology advantage by working with partners on stranded heavy oil resources around the world.

The Company s continuing strategy is as follows:

1. ***Execute.*** Execute on the two initial HTL™ projects: Tamarack in Canada and Pungarayacu in Ecuador.

2. ***Additional projects.*** Build on our two initial projects by capturing additional projects worldwide using the Company s HTL™ Technology.

3. ***Advance the technology.*** Continue to advance the HTL™ Technology through the first commercial application and beyond as well as continue the development of the technology and our intellectual property portfolio with our fully functional, third generation HTL™ processing facility, our feedstock test facility (**FTF**) in San Antonio.

4. ***Finance initial projects.*** Secure key partnerships and financing related to the initial two projects. The Company is actively working on various financing plans and establishing the relationships required for the development of Tamarack, Pungarayacu and additional projects in the future.

5. ***Build internal capabilities.*** We have made significant progress in building execution teams in order to execute the Company s first HTL™ projects. The Calgary based upstream team consists of a number of experienced heavy oil petroleum engineers, geologists and geotechnical experts attracted from major firms in Canada, complemented by thermal experts from the Company s Bakersfield office. The upstream team working on Pungarayacu consists

primarily of the Company s Bakersfield based team that has many years of South American experience with firms such as Occidental Petroleum. In addition, the Company s Houston-based HTL^{TM} technology team consists of a number of engineers that have an extensive background in chemical and petroleum refining, project engineering and the development and management of intellectual property. The Company expects to continue filling key positions in its execution mode.

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Executive Overview of 2009 Results

The following table sets forth certain selected consolidated data for the three-month and six-month periods ended June 30, 2009 and 2008:

	Three-Month Periods ended June 30,		Six-Month Periods ended June 30,	
	2009	2008	2009	2008
Oil revenues	$ 6,009	$ 11,746	$ 11,742	$ 22,635
Net loss from continuing operations	$ (11,444)	$ (18,547)	$ (23,021)	$ (26,977)
Net loss from continuing operations per share basic and diluted	$ (0.04)	$ (0.08)	$ (0.08)	$ (0.11)
Net loss and comprehensive loss	$ (11,378)	$ (21,731)	$ (23,652)	$ (30,275)
Net loss per share basic and diluted	$ (0.04)	$ (0.09)	$ (0.08)	$ (0.12)
Average production (Boe/d)	1,405	1,280	1,431	1,327
Net operating revenue per Boe	$ 27.88	$ 55.30	$ 25.46	$ 53.93
Cash flow provided by (used in) operating activities from continuing operations	$ (4,917)	$ 726	$ (9,797)	$ 2,396
Cash flow provided by (used in) operating activities	$ (2,886)	$ 2,626	$ (6,974)	$ 5,643
Capital investments	$ (6,692)	$ (1,880)	$ (11,900)	$ (4,720)

Financial Results Change in Net Loss

The following provides an analysis of the changes in net losses for the three-month and six-month periods ended June 30, 2009 as compared to the same periods for 2008:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	2009	*Favorable (Unfavorable) Variances*	2008	2009	*Favorable (Unfavorable) Variances*	2008
Summary of Net Loss by Significant Components:						
Oil Revenues:	$ 6,009		$ 11,746	$ 11,742		$ 22,635
Production volumes		*$ 1,132*			*$ 1,587*	
Oil prices		*(6,869)*			*(12,480)*	
Realized gain (loss) on derivative instruments	76	*2,207*	(2,131)	612	*3,467*	(2,855)
Operating costs	(2,444)	*2,859*	(5,303)	(5,145)	*4,468*	(9,613)
General and administrative, less stock based compensation	(3,332)	*(48)*	(3,284)	(8,779)	*(2,938)*	(5,841)
Business and technology development, less stock based compensation	(1,742)	*(539)*	(1,203)	(3,751)	*(1,285)*	(2,466)
Current (provision for) recovery of income taxes	639	*639*		(1,006)	*(1,006)*	
Foreign exchange loss	(2,680)	*(2,483)*	(197)	(1,686)	*(1,365)*	(321)
Net interest	(81)	*94*	(175)	(164)	*273*	(437)
Unrealized loss on derivative instruments	(1,249)	*11,629*	(12,878)	(1,704)	*13,132*	(14,836)
Depletion and depreciation	(6,045)	*386*	(6,431)	(12,000)	*1,340*	(13,340)
Stock based compensation	(526)	*267*	(793)	(987)	*924*	(1,911)
Future income tax recovery		(2,286)	2,286		*(2,286)*	2,286
Discontinued operations	66	3,250	(3,184)	(631)	*2,667*	(3,298)
Other	(69)	*115*	(184)	(153)	*125*	(278)
Net Loss	$ (11,378)	*$ 10,353*	$ (21,731)	$ (23,652)	*$ 6,623*	$ (30,275)

The net loss for the three-month period ended June 30, 2009 was $11.4 million ($0.04 net loss per share) compared to a net loss for the same period in 2008 of $21.7 million ($0.09 net loss per share). The decrease in net loss from 2008 to 2009 of $10.4 million was primarily due to reduced realized and unrealized losses on derivative instruments, decreases in operating costs, depletion and depreciation and stock based compensation and a change from a loss to income from discontinued operations, offset by a decrease in combined oil revenues, an increase in general and administrative and business and technology expenses and a decrease in the future income tax recovery.

The net loss for the six-month period ended June 30, 2009 was $23.7 million ($0.08 per share) compared to a net loss for the same period in 2008 of $30.3 million ($0.12 per share). The decrease in net loss from 2008 to 2009 of $6.6 million was mainly due to decreases in realized and unrealized losses on derivative instruments, operating costs, depletion and depreciation, stock based compensation and a reduced loss from discontinued operations, offset by a decrease in combined oil revenues, an increase in general and administrative and business and technology expenses

and a decrease in the future income tax recovery.
Significant variances are explained in the sections that follow.

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Revenues and Operating Costs

China

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Net Production:				
Boe	127,881	116,507	258,959	241,478
Boe/day for the period	1,405	1,280	1,431	1,327
	Per Boe		Per Boe	
Oil revenue	$ 46.99	$ 100.82	$ 45.34	$ 93.74
Field operating costs	16.74	22.06	17.86	19.42
Windfall Levy	1.71	21.92	1.33	19.11
Engineering and support costs	0.66	1.54	0.69	1.28
	19.11	45.52	19.88	39.81
Net operating revenue	27.88	55.30	25.46	53.93
Depletion	40.99	49.72	40.60	49.69
Net revenue (loss) from operations	$ (13.11)	$ 5.58	$ (15.14)	$ 4.24

The following is a comparison of changes in production volumes for the three-month and six-month periods ended June 30, 2009 as compared to the same period in 2008:

Production Volumes

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	Net Boe s		Percentage	Net Boe s		Percentage
	2009	**2008**	**Change**	**2009**	**2008**	**Change**
China:						
Dagang	123,894	111,662	11%	252,372	231,490	9%
Daqing	3,987	4,845	-18%	6,587	9,988	-34%
	127,881	116,507	10%	258,959	241,478	7%

Overall, net production volume at the Dagang field during the three-month and six-month periods ended June 30, 2009 increased by 125 Bopd and 104 Bopd when compared to the same periods in 2008 with the exit rate at June 30, 2009 being 1,681 Bopd compared to 1,671 Bopd at June 30, 2008. The natural field decline from 2008 to 2009 was offset by productivity increases from adding new perforations, fracture stimulations and water flood response. With no additional drilling planned for 2009, we expect future production rates for the remainder of 2009 to be less than the average for the first six months. The fracture stimulations planned for the remainder of 2009 will help offset this field decline.

Total volume changes from the quarter ended June 30, 2008 to the same period in 2009 resulted in increased revenues of $1.1 million. Production volumes for the six-month period ended June 30, 2009 when compared to the same period in 2008 resulted in increased revenues of $1.6 million.

Oil Prices

Oil prices decreased 53% and 52%, per Boe for the three-month and six-month periods ended June 30, 2009 resulting in a $6.9 million, and $12.5 million, reduction in revenue when compared to the same periods in 2008. Crude oil prices will likely remain volatile throughout 2009.

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The decreased revenues that resulted from decreases to oil prices during the three-month and six-month periods ended June 30, 2009 were partially offset by the realized gain on derivatives resulting from the settlements from costless collar derivative instruments. As benchmark prices fall below the floor price established in the contract, the Company is required to settle monthly (see further details on these contracts below under Unrealized Gain (Loss) on Derivative Instruments). The realized net gain on these settlements increased by $2.2 million, and $3.5 million, during the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2008. Changes in these realized settlement losses are shown below:

Three Months Ended June 30, 2009	*Favorable (Unfavorable) Variances*	Three Months Ended June 30, 2008
$ 76	$ 2,207	$ (2,131)

Six Months Ended June 30, 2009	*Favorable (Unfavorable) Variances*	Six Months Ended June 30, 2008
$ 612	$ 3,467	$ (2,855)

Operating Costs

Operating costs in China, including engineering and support costs and a windfall gain levy (a levy imposed at progressive rates on sales of oil), decreased 58% and 50% per Boe during the three-month and six-month periods ended June 30, 2009 as compared to the same periods in 2008. The majority of these decreases relate to a 92% and 93% per Boe drop in the Windfall Levy as oil prices decreased substantially from 2008. 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 the three-month and six-month periods ended June 30, 2009 this resulted in rates between 20% 30% or $1.71 and $1.33 per Boe as compared to a 40% levy rate or $21.93 and $19.11 per Boe for the same periods in 2008. Field operating costs decreased $5.32 and 1.56 per Boe for the three-month and six-month periods in 2009 over 2008. Additionally, effective January 1, 2009 the Dagang field reached Commercial Production status as defined by the Production Sharing Contract with China National Petroleum Company. The effect of this change is that the Company no longer pays 100% of operating costs but now pays 82%, representing the pre-cost recovery proportionate share. Had the Company paid the lower proportionate share noted above in the 2008 periods, field operating costs would have decreased $1.35 per Boe for the three-month period ended June 30, 2009 and increased $1.96 per Boe for the six-month period ended June 30, 2009 as compared to the same respective periods in 2008. The three-month period ended June 30, 2009 decrease per Boe is mainly due to lower road and lease costs which are weather related and lower travel and camp costs, partially offset by higher maintenance and workover costs, higher treatment and processing costs as total fluids input increased from 2008 levels and increased field office cost allocation as more activity in 2009 related to operations. The six-month period ended June 30, 2009 increase is due mainly from increased maintenance and workover costs, higher treatment and processing costs as total fluids input increased from 2008 levels and increased field office cost allocations as more activity in 2009 related to operations. On an absolute dollar basis, operating costs for the remainder of 2009 are expected to remain at approximately the same levels incurred in the first six months, however on a per Boe basis, costs are expected to increase as the number of barrels of oil produced decreases while the total level of fluid produced remains constant.

General and Administrative

Changes in general and administrative expenses, before and after considering a decrease in non-cash stock based compensation, by segment for the three-month and six-month periods ended June 30, 2009 as compared to the same periods for 2008 were as follows:

Six Months

	Three months Ended 2009 vs. 2008	Ended 2009 vs. 2008
Favorable (unfavorable) variances:		
Oil Activities:		
Canada	$ 273	$ 415
Ecuador	(459)	(976)
China	(72)	(35)
Corporate	259	(1,819)
	1	(2,415)
Less: stock based compensation	(49)	(523)
	$ (48)	$ (2,938)

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Canada

The Company acquired working interests in two leases located in Alberta, Canada in July 2008. Certain general and administrative costs, including salaries and benefits, related to Canada are now being capitalized.

Ecuador

In the fourth quarter of 2008 the Company signed a contract to explore and develop Block 20. General and administrative costs incurred prior to signing this contract were minimal.

China

The increase in general and administrative expenses related to the China operations for the three-month and six-month periods ended June 30, 2009 as compared to the same periods in 2008 mainly resulted from less capitalized overhead offset by a reduction in legal expense and certain fixed costs benefiting from a favorable shift in exchange rates.

Corporate

General and administrative costs related to Corporate activities decreased $0.3 million and increased $1.8 million for the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2008. When comparing the three-month periods, the following were areas where costs increased: an increase in corporate overhead of $0.4 million. The following details areas where costs decreased: a one-time severance compensation charge in the second quarter of 2008 in the amount of $0.3 million, a $0.2 million reduction for an executive that resigned in the second quarter of 2008 and reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008 of $0.3 million.

When comparing the six-month periods, the following were areas where costs increased: $3.0 million for legal and related fees (see Item 1 to Part II of this Form 10Q), corporate aircraft costs of $0.2 million and an increase in corporate overhead of $0.2 million. The following details areas where costs decreased: a one-time severance compensation charge in the second quarter of 2008 in the amount of $0.3 million, reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008 of $0.3 million, a $0.2 million reduction in salary for an executive that resigned in the second quarter of 2008, a decrease in stock based compensation due to a significant grant in the first quarter of 2008 in the amount of $0.6 million and executive recruiting fees in 2008 of $0.3 million.

Business and Technology Development

Business and technology development expenses increased $0.3 million and $0.9 million (including changes in stock based compensation) for the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2008 mainly as a result of a reallocation of certain executive salaries to business development activities at the beginning of the third quarter 2008, the start up of the FTF and several project financing initiatives in the first quarter of 2009.

Foreign Exchange Loss

The increase in foreign exchange loss period over period is mainly a result of the unrealized loss on Canadian dollar denominated long term debt.

Net Interest

Interest expense decreased $0.2 million and $0.4 million for the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2008 mainly due to a decrease in our long term debt resulting from a $3.0 million repayment on our loan for our China operations in the fourth quarter of 2008 and pay off of a short term Corporate note payable in the third quarter of 2008.

Unrealized Gain (Loss) on Derivative Instruments

As required by the Company s lender, the Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 50% of the Company s estimated production from its Dagang field in China over a three-year period starting September 2007. This derivative has a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using WTI as the index traded on the NYMEX.

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The Company accounts for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value and are a liability; conversely forecasted benchmark prices fall below the floor prices set in the contract, the contracts have a positive value and are an asset. Changes in these unrealized settlement (losses) and gains are detailed below:

Three Months Ended June 30, 2009	***Favorable (Unfavorable) Variances***	**Three Months Ended June 30, 2008**
$ (1,249)	$ 11,629	$ (12,878)

Six Months Ended June 30, 2009	***Favorable (Unfavorable) Variances***	**Six Months Ended June 30, 2008**
$ (1,704)	$ 13,132	$ (14,836)

Depletion and Depreciation

Depletion and depreciation decreased $0.4 million and $1.3 million for the three-month and six-month periods ended June 30, 2009 as compared to the same periods in 2008, respectively. This is mainly due to decreases in depletion rates for China offset by increase in volumes.

China

China s depletion rate decreased $8.73 and $9.09 per Boe for the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2008. These decreases in the rates from period to period were mainly due to lower future oil prices estimated at January 1, 2009 compared to January 1, 2008. Under the Production Sharing Contract, this price reduction delays full cost recovery in the Dagang field resulting in an increase in net reserves. Lower estimated future capital expenditures to develop proved undeveloped reserves also contributed to the decrease in the rate. These reductions were partially offset by an additional impairment to the Sichuan exploration costs added to the depletable base in the first two quarters of 2009.

Provision for/Recovery of Income Taxes

China

There was a current recovery of income taxes for the three-month period ended June 30, 2009 compared to a provision for income taxes for the six-month period ended June 30, 2009. Subsequent to the first quarter of 2009 and the 2008 tax calculations being finalized, the Company s tax advisors determined that there were additional deductible amounts that had not been included in the original calculations.

Discontinued Operations

In June of 2009, management commenced a process to sell all of the Company s United States oil and gas exploration and production operations. The Company completed the sale for total proceeds of $39.2 million in July 2009. The net proceeds from the sale totaled approximately $33.1 million, after repayment of debt in the amount of $5.2 million and transaction expenses estimated at $0.9 million. The net amount of gain/loss from discontinued operations declined for the three-month and six-month periods ended June 30, 2009 when compared to the same periods in 2009 due to the significant decrease in oil prices.

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Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

The following table sets forth a summary of our cash flows from continuing and discontinued operations for the periods indicated:

	Three-Month Periods ended June 30,				Six-Month Periods ended June 30,			
	2009		2008		2009		2008	
Net cash provided by (used in) operating activities	$	(2,886)	$	2,626	$	(6,974)	$	5,643
Net cash used in investing activities	$	(7,043)	$	(3,868)	$	(13,311)	$	(10,351)
Net cash provided by (used in) financing activities	$	(28)	$	4,765	$	(542)	$	3,566
Net increase (decrease) in cash and cash equivalents	$	(9,961)	$	3,523	$	(20,862)	$	(1,142)

As reflected in the accompanying unaudited condensed consolidated financial statements, we have losses from operations, negative cash flows from operations and have a substantial accumulated deficit. Historically, we have principally used external sources to fund operations, to fund acquisitions of oil and gas properties and projects, to service long term liabilities and to develop our technology and major projects. The main source of funds historically has been public and private equity and debt markets. The Company s cash flow from operating activities will not be sufficient to meet its operating and capital obligations, including the Zitong commitment described in Note 7 to the Unaudited Consolidated Financial Statements, and as such, the Company intends to finance its operating and capital projects from a combination of strategic investors in its projects and/or public and private debt and equity markets, either at a parent company level or at a project level.

Principal factors that could affect our ability to obtain funds from external sources include:

- Inability to attract strategic investors to our projects,
- Volatility in the public debt and private and equity markets,
- Increases in interest rates or credit spreads, as well as limitations on the availability of credit, that affect our ability to borrow under future potential credit facilities on a secured or unsecured basis, and
- A decrease in the market price for our common stock.

Operating Activities

Operating activities used $2.9 million in cash for the three-month period ended June 30, 2009 compared to $2.6 million cash provided for the same period in 2008. Operating activities used $7.0 million in cash for the six-month period ended June 30, 2009 compared to $5.6 million cash provided for the same period in 2008. The decrease in cash from operating activities for the three-month and six-month periods ended June 30, 2009 were mainly due to a decrease in oil and gas prices and an increase in general and administrative and business and technology development expenses when compared to the same periods in 2008.

Investing Activities

Investing activities used $7.0 million in cash for the three-month period ended June 30, 2009 compared to $3.9 million for the same period in 2008. Investing activities used $13.3 million in cash for the six-month period ended June 30, 2009 compared to $10.4 million for the same period in 2008.

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Changes in capital investments by segment are detailed below:

	Three-Month Periods Ended June 30,			Six-Month Periods Ended June 30,		
	2009	2008	(Increase) Decrease	2009	2008	(Increase) Decrease
Oil and Gas Activities:						
Canada	$ 4,009	$	$ (4,009)	$ 6,077	$	$ (6,077)
Ecuador	895		(895)	1,551		(1,551)
China	1,368	1,646	278	2,524	3,771	1,247
Business and Technology Development	420	231	(189)	1,694	946	(748)
Corporate		3	3	54	3	(51)
	$ 6,692	$ 1,880	$ (4,812)	$ 11,900	$ 4,720	$ (7,180)

Canada

As noted above, two leases located in Canada were acquired in the third quarter of 2008. Capital investments during the six-month period ended June 30, 2009 consisted of seismic/ERT, environmental work and capitalized interest.

Ecuador

The increase of investment activities in 2009 is due to the signing of a contract in October 2008 to explore and develop Ecuador s Pungarayacu heavy-oil field using our HTL[TM] Technology including the completion of environmental assessment activities, the receipt of environmental permits and licenses in May 2009 and preliminary costs related to the planning for appraisal drilling activities.

China

Capital asset expenditures decreased 17% or $0.3 million and 33% or $1.2 million in the three-month and six-month periods ended June 30, 2009 as compared to the same periods in 2008. Expenditures in the Dagang field decreased $0.3 million in the three-month period ended June 30, 2009 compared to the same 2008 period as fewer fracture stimulations were performed in 2009 versus 2008. For the six-month period ended June 30, 2009 expenditures at Dagang decreased $1.1 million compared to the same 2008 period due to less fracture stimulation activity in 2009 and an associated decrease in field office cost allocations. Expenditures in the Sichuan project decreased slightly from 2008 levels by $0.2 million for the six-month period ended June 30, 2009 compared to the same 2008 period due to lower personnel costs. We continue to move forward and obtain drilling locations prior to final approval for phase two of the exploration program.

Business and Technology Development

The increase in capital spending during the three-month period ending June 30, 2009 when compared to 2008 was due to the timing of costs relating to the construction and delivery of the FTF. Additionally, in 2009 there were modifications to the FTF to provide the capacity for longer term runs and enhance the facility s intellectual property development capabilities.

Financing Activities

Financing activities for the three-month and six-month periods ended June 30, 2009 consisted mainly of the final debt payments of a long term note. During these same periods in 2008 financing activities consisted of debt payments and professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary.

Outlook for balance of 2009

Our primary focus for the balance of 2009 will be to accelerate discussions with potential strategic and financing partners related to our projects in Ecuador and Canada. Progress on these discussions will determine the pace of execution of our two leading projects and the pace of related expenditures.

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In addition to the two identified projects, Tamarack and Pungarayacu, we are selectively pursuing other HTL opportunities in the Middle East and elsewhere around the world. Our goal is to develop a manageable portfolio of high quality, heavy oil opportunities on a worldwide basis.

With regard to Tamarack, our focus is on completing the HTL Front End Engineering & Design (FEED) work with AMEC, our London-based tier-one contractor.

With regard to Pungarayacu, Ecuador our focus for the balance of 2009 will be on our plan to drill between three and six appraisal wells. This proposed drilling activity will allow us to better characterize the oil and the reservoir in order to proceed with a full appraisal program in 2010.

Contractual Obligations

The table below summarizes the contractual obligations that are reflected in the Unaudited Condensed Consolidated Balance Sheet as at June 30, 2009 and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2009**	**2010**	**2011**	**2012**	**After 2012**
Consolidated Balance Sheets:						
Long term debt	$ 39,792	$	$ 6,652	$ 33,140	$	$
Asset retirement obligation	2,164		1,974			190
Long term obligation	1,900				1,900	
Other Commitments:						
Interest payable	5,043	1,358	2,572	1,113		
Lease commitments	2,934	737	1,032	703	336	126
Zitong exploration commitment	24,694	13,123	11,571			
Total	$ 76,527	$ 15,218	$ 23,801	$ 34,956	$ 2,236	$ 316

Off Balance Sheet Arrangements

As at June 30, 2009, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Outstanding Share Data

As at August 7, 2009, there were 279,381,187 common shares of the Company issued and outstanding. Additionally, the Company had 11,400,000 share purchase warrants outstanding and exercisable to purchase 11,400,000 common shares. As at August 7, 2009, there were 12,124,950 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							
	2009		2008				2007	
	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr
Total revenue								
Canadian GAAP	$ 4,844	$ 5,824	$ 19,524	$ 26,159	$ (3,249)	$ 8,235	$ 5,336	$ 7,391
U.S. GAAP	$ 4,280	$ 3,783	$ 24,919	$ 40,800	$ (15,453)	$ 5,068	$ 6,453	$ 10,962
Net income (loss) from continuing operations:								
Canadian GAAP	$ (11,444)	$ (11,577)	$ (16,322)	$ 4,822	$ (18,547)	$ (8,430)	$ (16,178)	$ (5,855)
U.S. GAAP	$ (8,985)	$ (10,158)	$ (27,189)	$ 20,206	$ (30,201)	$ (10,728)	$ (13,959)	$ 10,840
Net income (loss) from discontinued operations:								
Canadian GAAP	$ 66	$ (697)	$ 2,342	$ 5,240	$ (3,184)	$ (114)	$ (2,671)	$ (1,377)
U.S. GAAP	$ 1,151	$ 466	$ (18,210)	$ 5,618	$ (2,780)	$ 234	$ (2,266)	$ (13,391)
Net income (loss) per share continuing operations								
Canadian GAAP	$ (0.04)	$ (0.04)	$ (0.06)	$ 0.02	$ (0.08)	$ (0.03)	$ (0.07)	$ (0.02)
U.S. GAAP	$ (0.03)	$ (0.04)	$ (0.10)	$ 0.07	$ (0.12)	$ (0.04)	$ (0.06)	$ 0.05
Net income (loss) per share discontinued operations								
Canadian GAAP	$ 0.00	$ (0.00)	$ 0.01	$ 0.02	(0.01)	(0.00)	$ (0.01)	$ (0.01)
U.S. GAAP	$ 0.00	$ 0.01	$ (0.07)	$ 0.02	(0.01)	0.00	$ (0.01)	$ (0.06)

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 of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the second quarter of 2008 were mainly due to an additional negative $12.2 million fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net income and net income per share for the third quarter of 2008 were mainly due to an additional $14.6 million positive fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the fourth quarter of 2008 were mainly due to the additional ceiling test write downs for U.S. GAAP. The differences in the net income and net income per share for the first quarter of 2009 were mainly due to an additional $2.0 million negative fair value adjustment of derivative instruments for U.S. GAAP offset by reduced depletion of $4.4 million. The differences in the net loss and net loss per share for the second quarter of 2009 were mainly due to an additional $3.1 million additional depletion expense for Canadian GAAP.

Transition to International Financial Reporting Standards (IFRS)

In April 2008, the CICA published the exposure draft Adopting IFRSs in Canada . The exposure draft proposes to incorporate International Financial Reporting Standards (**IFRS**) into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

Under IFRS, the primary audience is capital markets and, as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed. The Company has not completed development of its IFRS changeover plan, which will include project structure and governance, deployment of resources and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential IFRS 1 exemptions. The Company hopes to complete its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, once the exemptions as described below relating to full cost oil and gas companies have been determined.

On July 23, 2009, the International Accounting Standards Board ("IASB") issued amendments to International Financial Reporting Standards 1, "*First Time Adoption of International Financial Reporting Standards*" ("IFRS 1"). The amendments address the retrospective application of IFRSs to particular situations and are aimed at ensuring that entities applying IFRSs will not face undue cost or effort in the transition process. One such exemption relating to full cost oil and gas accounting, exempts entities using the full cost method from retrospective application of IFRSs for oil and gas assets. Additionally, the amendment allows entities that have used full cost accounting under previous GAAP, to measure their exploration and evaluation assets, and assets in development or production phases, at the amount determined under the entity's previous GAAP, at the date of transition. For assets in production and development phases, the amount accumulated in the cost center is then allocated pro-rata to the underlying assets using reserve volumes or reserve values at the date of transition. To ensure that these assets are not stated at more than their recoverable amount, an entity that uses this exemption must test such assets for impairment at the date of transition to IFRS.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes from December 31, 2008. Further information presented on market risks can be found in our 2008 Form 10-K.

Item 4. Controls and Procedures

The Company s management, including its 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 June 30, 2009. 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 quarter ended June 30, 2009, 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.

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Part II Other Information

Item 1. Legal Proceedings:

The Company is a defendant in a lawsuit filed November 20, 2008 in the U.S. District Court for the District of Colorado by Jack J. Grynberg and three affiliated companies that alleges bribery and other misconduct and challenges the propriety of a contract awarded to the Company s wholly-owned subsidiary Ivanhoe Energy Ecuador Inc. to develop Ecuador s Pungarayacu heavy oil field. The plaintiff s claim is for unspecified damages or ownership of the Company s interest in the Pungarayacu field. The action is at an early stage and the parties are preparing their defense. All defendants have filed motions to dismiss the lawsuit for lack of jurisdiction. While the Company intends to rigorously defend the interest of the Company and its shareholders and considers the plaintiffs claim to be wholly without merit, the likelihood of any ultimate loss or gain, if any, on the Company s part is not determinable at this time.

Item 1A. Risk Factors:

The following risk factor is in addition to those risk factors more fully described in Item 1A. of our 2008 Annual Report on Form 10-K.

The Company s financial statements have been prepared in accordance with Canadian generally accepted accounting principles applicable to a going concern, which assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of operations. The Company has a history of operating losses and currently anticipates incurring substantial expenditures to further its capital development programs. The Company s cash flow from operating activities will not be sufficient to both satisfy its current obligations and meet the requirements of its capital investment programs. The continued existence of the Company is dependent upon its ability to obtain capital to meet its obligations, to preserve its interests in current projects and to meet the obligations associated with future projects. The Company intends to finance the future payments required for its capital projects from a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level. Public and private debt and equity markets may not be accessible now or in the foreseeable future and, as such, the Company s ability to obtain financing cannot be predicted with certainty at this time. Without access to financing, the Company may not be able to continue as a going concern.

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:

The Company held its Annual General Meeting of Shareholders (**AGM**) on April 15, 2009. The term of office of each incumbent director expired at the conclusion of the AGM. The following individuals were elected at the AGM as directors of the Company for a term expiring as of the conclusion of the Company s next AGM:

Name of Director Nominee	Votes in Favor	Votes Withheld
A. Robert Abboud	198,466,047	3,558,607
Howard Balloch	198,284,531	3,740,123
Brian F. Downey	198,574,399	3,450,255
Robert M. Friedland	181,559,895	20,464,759
Robert G. Graham	181,701,787	20,322,867
Peter Meredith	181,587,548	20,437,106
Robert A. Pirraglia	181,068,736	20,955,918

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Each of the following matters was also voted upon at the AGM:

Deloitte & Touche LLP were re-appointed as the Company s auditors for remuneration to be determined by the Company s Board of Directors (201,361,601 Common Shares voted in favor and 663,054 Common Shares withheld from voting); and

An ordinary resolution was passed ratifying the grant of 185,000 incentive stock options to two employees of the Company (106,011,137 Common Shares voted in favor and 28,796,550 Common Shares voted against).

Item 5. Other Information: None

Item 6. Exhibits

EXHIBIT NUMBER	DESCRIPTION
10.1	Stock Purchase Agreement among Ivanhoe Energy Holdings Inc., as Seller, Ivanhoe Energy Inc., as Seller Parent, Seneca South Midway LLC, as Purchaser and Seneca Resources Corporation, as Purchaser Parent.
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: August 10, 2009

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INDEX TO EXHIBITS

Exhibit Number	Description
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