

INTERNATIONAL SOVEREIGN ENERGY CORP.

Management's Discussion and Analysis

Form 51-102F2

For the Three Months Ended

March 31, 2010

May 12, 2010

INTERNATIONAL SOVEREIGN ENERGY CORP.

Management's Discussion and Analysis

The following discussion and analysis ("MD&A") of financial results is dated May 12, 2010 and is to be read in conjunction with the accompanying unaudited consolidated interim financial statements and related notes for the period ended March 31, 2010 of International Sovereign Energy Corp. ("ISR" or the "Company") and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2009.

Basis of Presentation –The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. The following MD&A compares the results of the three months ended March 31, 2010 to the three months ended March 31, 2009.

In this MD&A, production and reserves information may be presented on a "barrel of oil equivalent" or "boe" basis with six thousand cubic feet ("mcf") of natural gas being equivalent to one barrel ("bbl") of crude oil or natural gas liquids. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Non-GAAP Measurements – Within the MD&A references are made to terms commonly used in the oil and gas industry. Funds from operations, funds from operations per share and netbacks are not defined by GAAP in Canada and are referred to as non-GAAP measures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income per share. Netbacks equal total revenue less royalties and operating and transportation expenses calculated on a per boe basis. Management utilizes these measures to analyze operating performance and leverage. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash flow from operations or other measures of financial performance calculated in accordance with Canadian GAAP. Funds from operations is commonly referred to as cash flow by research analysts and is used to value and compare oil and gas companies and is frequently included in published research when providing investment recommendations. Total boes are calculated by multiplying the daily production by the number of days in the period.

The following table reconciles cash flow from operations to funds from operations used in the MD&A:

	Three Months Ended March 31,	
	2010 \$	2009 \$
Cash flow from operations	1,139,039	848,501
Changes in non-cash working capital	(246,274)	(556,324)
Funds from (used in) operations	892,765	292,177

Forward Looking Statements – Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and other similar expressions. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results of events to differ materially from those anticipated in these forward looking statements.

In particular, this MD&A contains the following forward looking statements pertaining to, without limitation, the following: ISR's future production volumes and the timing of when additional production volumes will come on stream; ISR's realized price of commodities in relation to reference prices; the Company's future commodity mix; future commodity prices; the Company's expectations regarding future royalty rates and the realization of royalty incentives; ISR's expectation of future operating costs on a per unit basis; the relationship of ISR's interest expense and the Bank of Canada interest rates; future general and administrative expenses; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected decrease to the depletion, depreciation and accretion rate; the estimated future contractual obligations of the Company and the amount expected to be incurred under its farm-in commitments; the estimated future capital expenditure of the Company; the future liquidity and financial capacity of the Company; and its ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

With respect to the forward looking statements contained in the MD&A, ISR has made assumptions regarding future commodity prices; the impact of royalty regimes and certain royalty incentives, the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continuation of the current tax and regulation.

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in, or incorporated by reference into this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in the Management's Discussion and Analysis; volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of ISR stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under "Risk Factors" in our Annual Information Form filed on SEDAR. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward looking statements contained in this document speak only as of the date of this document and ISR does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

Additional information relating to International Sovereign Energy Corp. is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at International Sovereign Energy Corp., 1750, 801 – 6th Avenue S.W., Calgary, Alberta T2P 3W2 or by accessing the website at www.isove.com.

Description of Business

International Sovereign Energy Corp. is a Calgary based, natural gas focused Company. The principal undertaking of the Company is to explore for, develop and hold interests in petroleum and natural gas properties. The primary operating regions are within Alberta and British Columbia, referred to as Berwyn, Clarke Lake, Boundary Lake, Marwayne, Medicine River and Wildmere. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol ISR.

SELECTED QUARTERLY INFORMATION

Quarterly Financial Summary

	2010		2009			2008		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	\$	\$	\$	\$	\$	\$	\$	\$
Financial								
Petroleum and natural gas sales	2,487,264	2,339,643	1,874,929	2,108,350	2,544,921	3,540,511	5,563,108	5,389,527
Cash in (out)flow from operations	1,139,039	(1,816,510)	417,466	(729,410)	848,501	(1,666,967)	3,577,011	2,418,264
Funds from operations	892,765	434,545	(226,213)	593,416	292,177	957,969	2,845,501	1,234,168
per share – basic	0.06	0.03	(0.01)	0.04	0.02	0.06	0.20	0.09
- diluted	0.06	0.03	(0.01)	0.04	0.02	0.06	0.18	0.09
Net income (loss)	(762,002)	(1,591,721)	(2,192,399)	(1,931,259)	(1,105,313)	(1,659,078)	1,149,935	(3,779,982)
per share – basic	(0.05)	(0.10)	(0.14)	(0.12)	(0.07)	(0.10)	0.08	(0.27)
- diluted	(0.05)	(0.10)	(0.14)	(0.12)	(0.07)	(0.10)	0.07	(0.27)
Petroleum and natural gas additions, net of dispositions	951,246	1,378,086	785,592	194,027	2,246,339	3,687,993	1,146,406	1,099,304
Working capital (deficit)	(5,244,204)	(5,077,229)	(4,078,141)	(2,665,672)	(4,605,014)	(2,650,843)	791,784	(3,269,170)
Total assets	27,979,406	29,240,197	28,905,379	31,131,417	37,306,332	37,117,644	38,289,202	36,592,301
Weighted shares outstanding								
Basic	16,096,084	16,096,084	16,096,084	16,096,084	16,096,084	16,096,084	14,210,867	13,928,084
Diluted	16,096,084	16,096,084	16,096,084	16,096,084	16,096,084	16,096,084	15,416,192	13,928,084
Operations								
Average daily production								
natural gas (mcf/d)	3,783	3,693	4,577	5,084	4,965	5,413	4,628	3,831
oil & ngl's (bbls/d)	133	145	84	118	129	150	195	216
combined (boe/d)	764	761	847	965	956	1,052	967	854
Operating netback (\$/boe)	19.57	17.99	13.17	11.03	12.55	19.21	38.34	45.75

- (1) Funds from operations is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. We consider it an important measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.. Throughout this MD&A funds from operations is defined as cash provided by operating activities before the changes in non-cash working capital.
- (2) Average realized prices are before transportation costs.
- (3) Operating netback is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP. We consider it an important measure as it demonstrates our operating efficiency and ability to generate the cash flow necessary to fund future growth through capital investment.

Operating Summary

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Company interest basis (working interest plus royalty interest), before deduction of Crown and other royalties, unless otherwise indicated. The Company's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather, general economic conditions and changes in the Canadian/United States ("US") currency exchange rate.

Production

The following table outlines the Company's sales and production for the periods:

		Three Months Ended March 31,	
		2010	2009
Natural gas	<i>mcf/d</i>	3,783	4,965
Crude oil and natural gas liquids	<i>bbl/d</i>	133	129
Combined (6:1)	<i>boe/d</i>	764	956

Production for the three months ended March 31, 2010 (the "quarter") averaged 764 boe per day consisting of 3,783 mcf per day of natural gas and 133 bbls per day of crude oil and natural gas liquids. Production during the quarter was 20% lower than the same period in 2009 of 956 boe per day mainly due to Company's larger gas producers encountering water issues in the fourth quarter of 2009. The Company's production portfolio for the quarter was weighted 82% to natural gas and 18% to crude oil and natural gas liquids.

Average Realized Prices

		Three Months Ended March 31,	
		2010	2009
Natural gas	<i>\$/mcf</i>	5.11	4.42
Crude oil and natural gas liquids	<i>\$/bbl</i>	62.18	47.33
Combined (6:1)	<i>\$/boe</i>	36.17	27.71

The Company's realized natural gas price the quarter was \$5.11 per mcf (2009 - \$4.42) compared to the AECO daily index spot average of \$4.70 per gigajoule ("gj") and the AECO monthly index average of \$5.11 per gj (2009 - \$4.69 per gj and \$5.19 per gj, respectively). The Company markets its natural gas on the daily spot market.

North American natural gas prices slowly weakened through the quarter. Colder than normal weather throughout the US and Canada during the first six weeks gave way to seasonal and warmer weather in most regions by the quarter end. As a result, the volume of gas withdrawn from storage due to cold weather slowed through the quarter while domestic US production continued to increase.

Natural gas markets continue to be dominated with bearish sentiment as robust production growth and slow demand recovery contributed to the sizable volume of gas in storage. However, recent downward revisions to North American LNG deliveries, warmer than normal summer weather forecasts and near record low water levels for hydro electric generation are expected to boost the demand side of the equation into summer. In addition, debate continues over the magnitude of the gas production growth and the decline rates of new shale production. The size of the actual supply additions have the potential to swing gas prices up or down depending on the effect to the supply and demand balance.

The Company's realized prices for its crude oil and liquids streams for the quarter were \$62.18 per bbl (2009 - \$47.33 per bbl).

Crude oil market fundamentals caused prices to dip downward and then recover through the quarter. Crude oil and refined product inventories which began the year with the largest five week decline since 1999 changed direction to build volume in February when weather related demand dropped with warmer temperatures and refinery utilization fell when several facilities performed maintenance turn-arounds. Market demand remained sluggish through the quarter in spite of the release of numerous reports showing positive economic growth while OPEC production quotas which started the year with 58 percent member compliance continued to see members over produce their quotas and finished the quarter with only 50 percent compliance. Oil markets were also subject to a weakening of the US dollar, the debt crisis in Greece and the ongoing nuclear dispute with Iran.

Crude oil prices which dropped during February, managed to recover and close at a high in the quarter even with the generally bearish market sentiment. Given this resilience and the positive economic news released through the quarter, demand is anticipated to grow at a quickening pace into the summer as the market focuses on the driving season.

Benchmark Commodity Prices

		Three Months Ended March 31,	
		2010	2009
		\$	\$
AECO natural gas (Daily index)	<i>Cdn\$/GJ</i>	4.70	4.69
AECO natural gas (Monthly spot)	<i>Cdn\$/GJ</i>	5.11	5.19
WTI crude oil	<i>US\$/Bbl</i>	78.68	42.86
Edmonton par crude oil	<i>Cdn\$/Bbl</i>	80.31	50.15
Hardisty heavy crude oil	<i>Cdn\$/Bbl</i>	68.78	39.38
Exchange rate	<i>Cdn\$/US\$</i>	1.0409	1.2453

Sensitivity analysis

The following table sets forth management's estimates of the sensitivity of cash flow expected to be generated by the Corporation in 2010 based on internal estimates. The estimates contain numerous assumptions and anticipate a capital expenditure program of approximately \$0.5 million. The budget does not include capital for any significant acquisitions, but the Company continues to pursue such opportunities and management believes the Company will be able to fund such acquisitions outside of the budget.

	Variance in Factor	Variance in Annual Cash Flow
AECO natural gas	CDN \$0.10/mcf	2,448
WTI crude oil	US\$1.00 bbl	24,683
CDN/US \$	CDN \$0.01	18,670

Petroleum and Natural Gas Revenue

	Three Months Ended March 31,	
	2010	2009
	\$	\$
Natural gas	1,740,334	2,098,478
Crude oil and natural gas liquids	746,930	446,443
Total	2,487,264	2,544,921

For the quarter, petroleum and natural gas revenue decreased two percent to \$2,487,264 from \$2,544,921 for the same period in 2009 as the decline in overall production was offset by an increase in the averaged realized prices reported.

Royalties

	Three Months Ended March 31,	
	2010	2009
	\$	\$
Crown	477,710	483,647
Freehold	34,827	4,979
Gross overriding	33,300	29,227
Total	545,837	517,853
As % of oil and gas revenues	21.9	20.3
\$/boe (6:1)	7.94	6.02

For the quarter, royalties increased five percent to \$546,000 from \$518,000 for the same period in 2009. Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. The Company's average royalty rate for the quarter was 21.9 percent, higher than 2009 of 20.3 percent. The increase in the royalty rate is mainly due to higher crude oil and NGL prices.

Management anticipates, based on current commodity prices and royalty regimes, the average royalty rate for 2010 will be approximately 20 to 24 percent of petroleum and natural gas revenue.

Alberta Royalties

On October 25, 2007, the Alberta government announced the New Royalty Framework ("new framework"), which took effect on January 1, 2009. The new framework is based on a new simplified royalty formula for natural gas that operates on a sliding scale determined by commodity prices, well productivity and drilling depth. The Company's Deep Basin well depths range between 2,300 to 2,700 meters which are eligible for the new measure depth drilling formula.

On November 19, 2008, the Alberta government announced that in response to the global economic crisis and a slowdown in crude oil and natural gas drilling throughout the province, it has implemented a transitional royalty program in which, companies drilling certain new wells after November 19, 2008, have a one-time option of selecting the transitional royalty program or the new framework. All wells drilled between 2009 and 2013 that adopt the transitional royalty program will be required to shift to the new framework on January 1, 2014. As a result, all of the Company's Alberta wells, drilled before November 19, 2008 are now under the new framework. For all Alberta wells drilled after November 19, 2008, the Company has completed the required elections for those wells it has determined would economically benefit under the transitional royalty program

On March 3, 2009, the Alberta government made a third announcement regarding royalties which provided incentives for the energy sector in response to the current global economic slowdown. The incentives include a drilling royalty credit for new conventional oil and natural gas wells of up to \$200 per meter drilled and a maximum five percent royalty rate for the first year of

production from new oil or gas wells brought on production after April 1, 2009. On June 25, 2009, the Alberta government extended these incentives to March 31, 2011. The drilling royalty credit may be reduced depending on the amount of Alberta production on crown lands and how much crown royalties are paid. ISR has determined that it qualifies for the full credit. ISR is continuing to assess the impact of the incentives and will adjust drilling plans and the timing of bringing wells on production accordingly. As at December 31, 2009, \$148,000 in Alberta drilling credits have been earned and recognized as a reduction to capital spending.

On March 11, 2010, the Alberta government announced modification of conventional oil and natural gas royalty rates to promote more innovation and use of new technologies. The new rates will become effective on a permanent basis for January 2011 production month. The current incentive program rate of five percent on new natural gas and conventional oil wells will become a permanent feature of the royalty system with current time and volume limits. The maximum royalty rate for conventional oil will be reduced at higher levels from 50% to 40%. The maximum royalty rate for conventional and unconventional natural gas will be reduced at higher levels from 50% to 36%. The transitional royalty framework for oil and gas introduced in November 2008 will continue until original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. All royalty curves will be finalized and announced by May 31, 2010.

British Columbia Royalties

On August 6, 2009, the government of BC announced an oil and gas stimulus package to enhance BC's competitive business climate and encourage continued oil and gas development and exploration. The package is comprised of two parts: a two percent royalty relief program and a change to the deep royalty credit program. The two percent royalty relief program applies to all natural gas wells drilled in a 10 month window (August 31, 2009 to July 1, 2010). The two percent royalty will apply to the first 12 months of production where production must commence before December 31, 2010.

The change to the deep royalty credit program includes an increase of 15 percent to the existing royalty deductions for natural gas deep drilling and the inclusion of horizontal wells drilled between 1,900 to 2,300 metres. The change applies to wells spud after August 31, 2009.

The two percent royalty relief program and the deep royalty credit program will co-exist but a company will only receive the benefits of one program at a time. The deep royalty credit will apply first. If the deep royalty credit is exhausted before 12 months of production, the two percent royalty will be in effect for the remainder of the 12 months. If the deep royalty credit is not exhausted before 12 months, the two percent royalty program will not apply.

ISR is continuing to review the incentives available in both Alberta and BC and has considered the benefits of each program in its future drilling plans.

Operating and Transportation

	Three Months Ended	
	2010	2009
	\$	\$
Operating and transportation expenses	595,546	786,713
\$/boe (6:1)	8.66	9.14

Operating and transportation expenses during the quarter decreased 24 percent to \$596,000 from \$787,000 for the same period in 2009. This reduction in operating and transportation costs was due to the decline in gas production combined with lower operating costs, specifically reduced water handling, at key properties such as Berwyn. On a boe basis, operating expenses for the quarter decreased five percent to \$8.66 per boe from \$9.14 per boe in the same period in 2009.

Management anticipates operating and transportation expenses for 2010 to average \$8.50 per boe.

Operating Netback

The following table summarizes the operating netbacks for natural gas and oil properties for the three months ended March 31, 2010 compared to the same period in 2009:

\$/boe	Three Months Ended March 31,	
	2010	2009
Petroleum and natural gas revenue	36.17	27.71
Royalties	(7.94)	(6.02)
Operating and transportation expenses	(8.66)	(9.14)
Operating netback	19.57	12.55

General and Administrative Expenses ("G&A")

	Three Months Ended March 31,	
	2010	2009
	\$	\$
Gross G&A expenses	425,323	747,128
Capitalized G&G expenses	-	-
Overhead recovery	(20,026)	-
General and Administrative Expenses	405,297	747,128
\$/boe (6:1)	5.89	8.68

General and administrative expenses ("G&A") net of overhead recoveries for the quarter of 2010 were \$405,000 or \$5.89 per boe compared to \$747,000 or \$8.68 per boe for the same period of 2009. The decrease in net G&A expenses on a per boe basis from the first quarter of 2009 is due to decreased management costs associated with the change in personnel during the first quarter of 2009.

At March 31, 2010, ISR had four full time employees and two full time consultants.

Interest Expense

	Three Months Ended March 31,	
	2010	2009
	\$	\$
Interest expense	24,273	-
\$/boe (6:1)	0.35	-

Interest and bank management fees were \$24,273 in Q1 2010. The Company had paid the revolving line of credit in its entirety by Q4 2008 and therefore, did not incur any interest fees in Q1 2009. The Company had \$3.2 million outstanding at the end of Q1 2010 compared to \$3.3 million at the end of Q1 2009.

Stock-Based Compensation Expense

	Three Months Ended	
	March 31,	
	2010	2009
	\$	\$
Stock-based compensation expense	49,329	44,734
\$/boe (6:1)	0.72	0.52

For the three months ended March 31, 2010, the Company recorded \$49,329 of stock-based compensation expense for stock options outstanding during the period as compared to \$44,734 for the first quarter of 2009. The increase of stock-based compensation expense is the result of options granted in the balance of 2009, options granted in January 2010, and adjusting the amortization method of recording this expense from a straight-line to a graded vesting calculation, keeping the vesting period constant. The change in estimate better reflects the benefit received and the vesting of that option benefit. The graded vesting method recognizes a larger portion of expense in the first and second year of amortization and vesting.

Depletion, Depreciation and Accretion

	Three Months Ended	
	March 31,	
	2010	2008
	\$	\$
Depletion and depreciation	1,855,893	1,902,451
Accretion	53,979	44,207
Total	1,909,872	1,946,658
Depletion and depreciation \$/boe (6:1)	26.99	22.11
Accretion \$/boe (6:1)	0.78	0.51
	27.77	22.62

Depletion and depreciation of property and equipment are calculated based upon capital expenditures, production rates and reserves. The Company excludes unproved property costs, seismic and salvage values in its calculation of depletion and depreciation, but includes future development costs in the capital base. Accretion of asset retirement obligations is included in the depletion, depreciation and accretion expense ("DD&A").

The Company recorded \$1.9 million or \$27.77 per boe of DD&A in the first quarter of 2010 compared to \$1.9 million or \$22.62 per boe in the first quarter of 2009.

Accretion

Accretion represents the change in the time value of asset retirement obligations ("ARO"). ARO is a balance sheet provision based on the Company's net ownership in wells and facilities. Management estimates the cost to abandon and reclaim the wells and facilities and the estimated time period during which these costs will be incurred in the future. Management estimates the total undiscounted amount of future cash flows required to abandon and reclaim wells and facilities as at March 31, 2010 to be approximately \$3.8 million to be incurred between 2010 and 2025. The Company used a discount rate of 8% to calculate its ARO obligations.

Underlying ARO may be increased over the period based on new obligations incurred from drilling wells or constructing facilities. Similarly, this obligation can be reduced as a result of abandonment work undertaken thereby reducing future obligations. There has been \$54,000 recognized as accretion expense for the first quarter of 2010 compared to \$44,000 for the first quarter of 2009.

Income Taxes

The provision for future income taxes for the quarter was a recovery of \$248,000 compared to the recovery reported in 2009 of \$360,000. The recovery for the quarter was largely due to the change in temporary differences recognized for the petroleum and natural gas assets.

The estimated tax pool balances as at March 31, 2010 total approximately \$19.8 million.

Net Loss and Comprehensive Loss

Net loss and comprehensive loss for the quarter decreased 31 percent to \$762,000 compared to net loss of \$1.1 million for the same period in 2009. The decrease was due to lower operating costs and general and administrative costs reported during the three months ended March 31, 2010. The basic and diluted net loss for the quarter was \$0.05 per share and for the same period in 2009 basic and diluted net loss was \$0.07 per share.

Capital Expenditures

During the quarter, the Company invested \$951,000 in capital expenditures compared to \$ 2.2 million in the same period in 2009.

	Three Months Ended March 31,	
	2010	2009
	\$	\$
Land	118,273	42,174
Geological and geophysical	10,813	619,026
Drilling and completion	774,749	1,527,495
Equipment, facilities and pipelines	23,175	56,050
Furniture and equipment	24,236	1,594
Total	951,246	2,246,339

During the quarter, the Company's capital expenditures were associated with the final phases of projects that began in December 2009, whereas in the same quarter of 2009 ISR had drilled two wells. The costs reported for the quarter ended March 31, 2010 were reported net of drilling incentives received of approximately \$40,000.

Due to commodity prices remaining low and the monitoring of the cash flow and revolving line of credit, the Company will be closely monitoring the expenditures during 2010.

Equity

	Three Months Ended March 31,	
	2010	2009
Shares Outstanding		
Basic	16,096,084	16,096,084
Diluted	18,352,728	18,352,728
Weighted average shares outstanding		
Basic and diluted	16,096,084	16,096,084

Liquidity and Capital Resources

As at March 31, 2010 the Company had negative working capital \$5.2 million, including the current outstanding revolving line of credit balance. Generally, ISR uses a combination of funds from operations, bank debt and equity issues to finance its capital expenditure program.

At March 31, 2010 the Company had a \$10.0 million revolving line of credit facility. Following April 2010 review, the bank reduced the facility to \$6.5 million, primarily due to reduction of reserves and current level of natural gas prices. The facility will be reviewed in August 2010. The Company is required to maintain a working capital ratio of 1:1, defined as current assets, including undrawn availability, to current liabilities, excluding bank debt. The operating loan bears interest at prime plus 2.0% and is secured by a demand debenture for a maximum of \$25.0 million providing a floating charge over all assets of the Company and a letter of undertaking to encumber or dispose of assets, other than in the normal course of business without consent of the financial institution and to provide security under section 426 of the Bank Act and/or assign natural gas contracts. As at March 31, 2010, \$3,157,371 (March 31, 2009 – nil) was drawn against the revolving credit line, and had letters of credit in place in the amount of \$7,500.

As at March 31, 2010 ISR had 16,096,084 voting common shares outstanding and 985,000 options to purchase common shares outstanding. The outstanding options have a weighted average exercise price of \$1.16 per share. As at March 31, 2010, the Company had 1,626,644 warrants outstanding.

The oil and gas business is inherently risky and capital intensive and can require significant capital and cash resources to expand by growing reserves, production and cash flow. Given the nature of the oil and gas business, and the size of ISR, it must be able to continue to access capital markets to raise additional monies to grow.

The Company has budgeted approximately \$0.5 million in capital expenditures for the balance of 2010 and expects to rely on internally generated cash flows and available lines of credit to fund its capital program.

Contractual Obligations

As part of normal operations, the Company is party to various financial guarantees, letters of credit and other contractual commitments. Oil sales from Company production are contracted on a month-to-month evergreen basis and gas sales from Company production are contracted on an annual basis commencing each November. The CEO/CFO is party to a separate employment services agreement with the Company. The Company also has a letter of credit outstanding totaling \$7,500 to maintain its status as a licensed well operator in the province of British Columbia. The Company also has two performance guarantees \$313,930 (PKR 25.9 million) and \$457,020 (US\$450,000) which expired on July 20 and November 8, 2009, respectively. However, the Company considers both guarantees to be active and has accrued for the liability.

The Company also has a legal obligation to reclaim the lands on which it has production wells and/or facilities. These obligations come due at varying times, dependent upon when economic production ceases and the property is then available for abandonment and reclamation operations.

Obligations with a fixed term for the remainder of 2010 and the next year are as follows:

		2010	2011
Office lease base rent (Expiring August 2011)		\$ 106,839	\$ 94,968

As part of its ongoing operations, the Company may be involved in potential litigation or claims associated with its international operations. Management is of the opinion that there will be no material impact on the financial position, results of operations or liquidity of the Company, as a result of such claims.

Off Balance Sheet Transactions

There were no off balance sheet transactions entered into during the period, nor are there any outstanding as of the date of this MD&A.

Outlook

The Company's performance to date in 2010 has been adversely affected by the substantial decline in energy prices from the 2008 levels. Although prices seem to be recovering, the Company will adjust its strategy in order to be better equipped to handle the future volatility of specifically the natural gas markets. The Company plans to accomplish this through both merger/acquisition possibilities combined with rebalancing the production portfolio more towards a 50:50 oil to gas ratio. Through such a program, the Company will increase production, revenue and profit streams and be able to generate the funds to fund further acquisitions as those become available.

The Company has recently evaluated its portfolio and has identified potential areas within its portfolio where further development of oil assets can be undertaken at minimal cost, and is in the process of disposing of minor non strategic assets.

Natural gas prices remained virtually unchanged in Q1 2010 at \$4.70/GJ compared to that recognized in Q1 2009 of \$4.69/GJ. While partially influenced by the strength of crude oil price changes, natural gas price changes are predominantly based on supply and demand fundamentals in the North American market.

Crude oil prices experienced a significant drop from the peak in mid-July 2008 for West Texas Intermediate ("WTI") of more than US\$145.00/bbl to a range of between US\$60.00 to \$70.00/bbl in late October 2008. Since that time, the global demand has pushed the price of oil back up, with the WTI price averaging \$78.68/bbl for Q1 2010, compared to the \$42.86/bbl of Q1 2009.

The Company will continue to review its capital expenditure program in light of the current economic climate. Since the present portfolio is approximately 80% gas, the Company will focus on opportunities that increase the oil component because we feel that the present outlook for near term gas prices versus oil prices is less favourable.

Strategic Direction

The Company realizes that although it presently possesses a relatively strong balance sheet, its sector is currently out of favour with the investing public and has and continues to explore avenues to increase shareholder value. Since the portfolio is heavily weighted towards gas the Company is captive to the North American economic recovery, which is presently subject to an overabundance of supply.

Hedging

The Company is prepared to participate in a hedging program at the appropriate price point; however given the size of the Company it must recognize the risk inherent in prices moving against any hedge in this market of volatile gas prices.

Domestic

With focus of the Company shifting towards oil opportunities, the Company plans to develop its current portfolio with a view of increasing its oil production. Specifically, the Company is exploring the idea of 'reactivating' its Marwayne heavy oil property. If the initial reactivation pilot well proves to be successful, which is planned for the latter half of Q2 2010, the property could again hold substantial value for the Company. The Marwayne property also holds the potential for further development drilling in which the Company plans to execute during Q3 2010.

The Company is pursuing plans mentioned in the previous section in order to move its portfolio towards more oil, as well as continuing to explore the acquisition of oil bearing assets and increasing its portfolio of undeveloped land for future exploration and development in order to increase future reserves, production and cash flow so as to maximize shareholder value.

International

The international properties in Pakistan and Ecuador will receive appropriate attention so that the Company can best benefit from those significant investments.

Pakistan

The Company signed two farm-in agreements with Mari Gas Company (“MGCL”) of Pakistan, the second largest producer of gas in Pakistan. The Company’s direct working interest (“WI”) in each block is 15% with all the work and management performed by a local seasoned and well established gas producer. The farm-in agreement provides that the Company be responsible for 25% of the development costs of the three wells in the Sukkur field. This 2,416.43 square kilometre block is situated in Sindh Province (100 kms from Karachi), Southern Pakistan. The block is situated next to the Badin area which contributes some 50% of Pakistan’s hydrocarbon production. Numerous oil and gas discoveries exist to the east of the block. Numerous oil and gas discoveries exist to the east of the block. MGCL has completed the reinterpretation of vintage 2D seismic from which a Lower Goru sand lead has been identified.

The Sukkur Joint Venture (“SJV”) is comprised of MGCL, the operator, with a 50% WI, Petroleum Exploration Limited, a Pakistani exploration and production company with a 35% WI and the ISR, with a 15% EI. The SJV committed to drill three exploration wells in the Sukkur Exploration Block.

On May 27, 2009, the Company was informed by MGCL that the Company was in default of non-payment of cash calls of its 15% WI the Sukkur and Sujawal blocks, if payment of all outstanding cash calls of approximately US\$1.2 million was not paid within seven days. Under the Joint Operating Agreement (“JOA”), the Company has the right to remedy the default during a period of 60 days by making payment of all its share of the cash calls with interest at three percent over LIBOR or forfeit its WI. In the event of forfeiture, the Company will not be entitled to receive any consideration for such forfeited working interest.

The Company had taken a provision of \$2.9 million in 2008 against international expenditures in Pakistan. The Company has provided for the capital expenditures and the cash calls relating to these blocks. In addition, the Company had posted performance bonds of \$313,930 (PKR25,966,080) and \$457,020 (US\$450,000), and a potential liability of \$737,000 (US\$725,000), all of which have been provided for in the financial statements for the year ended December 31, 2009, and for period ended March 31, 2010.

The Company is of the opinion that capital is presently better spent on its domestic drilling program that has substantially shorter payback periods. The Company has thus elected not to remedy the default, but to seek out parties that would take over its obligations. Although the Koonj Well, in the Sukkur Block, drilled in July 2008, has proven reserves, the operator has yet to start production despite assurances going back to November 2008. The company is not confident that the production will commence in a timely manner, and the initial reserve estimates subsequent to drilling have been downgraded substantially.

On August 1, 2009, the Company was granted a temporary injunction until August 8, 2009, that stays MGCL and Petroleum Exploration (Pvt) Limited (“PEL”) from forfeiture of the Company’s WI in the Sukkur block.

On September 2, 2009, the Company filed application for contempt of court and the court issued initial contempt notices to the Company’s working interest partners in the Sukkur Block, who have ignored the injunction and have tried to forfeit the Company’s working interest. The notices were successfully issued on September 4, 2009 with a hearing date set, however due to subsequent adjournments the case is yet to be heard.

On October 3, 2009, the Company was granted a temporary injunction that stays MGCL from seeking forfeiture of the Company’s WI in the Sujawal Block until October 5, 2009, and due to subsequent adjournments the arguments on the injunction application for the Sukkur Block and for written statement of MGCL in the Sujawal Block have yet to be heard.

The Company is currently in the process of attempting to reach a settlement with its partners in Pakistan.

Ecuador

Management continues to review this investment with a view to determine if it fits the Company’s risk profile. The Charapa Concession (“Charapa”) is currently being analyzed in detail and a work plan has been developed, in conjunction with the local authorities, to identify the method to achieve the maximum returns for both the Company and for Ecuador. This project is 100% owned by the Company and, as such, the Company is responsible for 100% of the costs and the inherent risks with, what is in effect, an under developed property. All environmental permits have been received. The Company continue to examine

whether or not continuation of this investments financially viable given that its banking covenants only allow cash flow from domestic operations to fund international operations.

On September 9, 2009, the Company received a deposit of US\$100,000 in escrow thereby accepting a non-binding letter of intent to sell its interest in the Charapa Marginal Oil Field in Ecuador. Subject to due diligence and negotiation of a definitive agreement, the consideration for the purchase of Charapa includes US\$3.0 million and replacement of the Company's performance guarantee of US\$2.34 million to Petroecuador.

The Company is still in the process of having the work plan approved by Petroecuador. Subsequent to obtaining the approval, the Company will be in a position to proceed to conclude the transaction and move to a definitive agreement.

Financial Instruments

Financial instruments comprise cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and a revolving line of credit. The fair values of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to their short term-maturities. The revolving line of credit bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

Disclosure Controls and Procedures ("DC&P")

The Company has established disclosure controls, procedures and policies so that the consolidated financial results are presented accurately, fairly and timely. The disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under applicable securities regulation is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure, and concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable, but not absolute assurance, that financial information is accurate and complete.

Internal Controls over Financial Reporting ("ICFR")

The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's internal controls over financial reporting ("ICFR") are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company.

Management has assessed the effectiveness of the Company's internal control over financial reporting as defined by Multilateral Instrument 52-109, Certification of Disclosure in Issuer's Annual and Interim Filings. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations. There were no changes made to the Company's ICFR during the three months ended March 31, 2010, that have materially, or are reasonably likely to materially affect, the Company's ICFR.

Because of their inherent limitations, ICFR and DC&P may not prevent or detect misstatements, errors or fraud. It should be noted that while the Company's Management including the Chief Executive Officer and Chief Financial Officer believe that the Company's internal controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that these controls will prevent all errors and fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the controls are met.

During the process of management's assessment, it was determined that a deficiency existed in the ICFR. Segregation of duties was identified as an area where a deficiency exists. Specifically, certain duties within the accounting department were not segregated due to the limited number of individuals employed in this area. The risk of a material misstatement is mitigated by direct involvement of senior management in the day to day operations of the Company and review of the financial statements and disclosures by senior management and the Board of Directors. However, these mitigating procedures are not considered sufficient to reduce the likelihood that a material misstatement would not be prevented or detected. This weakness and its

related risks is not uncommon in an entity of the size of the Company. As the Company grows, it plans to expand the number of individuals involved in the accounting function.

Critical Accounting Estimates

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires management to make judgments and estimates that affect the financial results of the Company. ISR management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 2 to the consolidated financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves - All of the Company's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Depletion Expense – The Company uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation or for impairment, for which many write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test – The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations – The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes – The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Change in Accounting Policies and Recent Accounting Pronouncements

Convergence with International Reporting Standards

On January 1, 2011 International Financial Reporting Standards (“IFRS”) will become the generally accepted accounting principles in Canada. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by ISR for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. Throughout 2009 the Company has assessed the impact of adopting IFRS and is continuing to implement plans for transition. The project is being managed by outside independent accounting professionals. The Company’s auditors will be involved throughout the process to ensure the Company’s policies are in accordance with these new standards.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact on the financial statements of adopting IFRS. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to ISR’s adoption of IFRS, Management’s plan is subject to change based on new facts and circumstances that arise after the date of the MD&A.

In July 2009 an amendment to IFRS 1 First Time Adoption of International Reporting Standards was issued that applies to oil and gas assets. The amendment allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity’s previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity’s previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. ISR currently anticipates that it will use this exemption. IFRS 1 also provides a number of other optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for the Company which other than the full cost accounting exemption noted above are:

Business Combinations – IFRS 1 would allow ISR to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based payments – IFRS 1 allows ISR an exemption on IFRS 2, “Share-based Payments” to equity instrument which vested before ISR’s transition date to IFRS.

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. At this time, ISR has identified key differences that will impact the financial statements as follows:

Exploration and Evaluation (“E&E”) expenditures – On transition IFRS, ISR will re-classify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. This will consist of the book value of undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.

Depletion expense – On transition to IFRS, the Company has the option to base the depletion calculation using either proved reserves or proved and probable reserves. ISR has not concluded at this time which method it will use.

Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed on specific portions of PP&E as opposed to the entire PP&E balance which is currently required under Canadian GAAP through the full cost ceiling test. Impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves. Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009 and the issuance of the exposure draft on IAS 37 Provision, Contingent Liabilities and Contingent Assets in January 2010, Management is still determining the impact of these revised standards on its IFRS transition.

In regards to internal controls over financial reporting (“ICFR”), ISR will be determining which additional changes to ICFR will be required to deal with the changes in accounting policies. This will be ongoing through 2010 to ensure all changes in accounting policies include appropriate additional controls and procedures for future IFRS reporting requirements.

In regards to disclosure controls and procedures, ISR will be assessing stakeholders' information requirements and ensure that appropriate and timely information is provided once available

The Company is currently testing updates to its systems in regards to IFRS, which primarily involved updates to its accounting system. The modifications were not significant, however, they will allow the Company to report both Canadian GAAP and IFRS statements and track E7E costs, transfers from E&E to PP&E and allocation of PP&E into cash generating units.

The Company will have an opening January 1, 2010 balance sheet, which is in accordance with IFRS. The Company will maintain both Canadian GAAP and IFRS compliant financial statements in 2010.

Business Combinations

The accounting standard section 1582 "Business Combinations" was issued (the "new standard") and replaced the previous business combinations standard (the "current standard"). The new standard applies prospectively to business combinations on or after January 1, 2011 with earlier adoption permitted. Under this standard, the purchase price used in a business combination is based on the fair value of shares exchanged at the market price at the acquisition of closing date. Under the current standard, the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is announced. In addition, the new standard requires all acquisition costs to be expensed while the current standard allows for the capitalization of these costs as part of the purchase price. The new standard also addresses contingent liabilities, which will be required to be recognized at fair value on acquisition and subsequently remeasured at each reporting period until settled. The current standard requires only contingent liabilities that are payable to be recognized. The new standard requires negative goodwill to be recognized in earnings rather than the current standard of deducting from non-current assets in the purchase price allocation. ISR is currently assessing the impact of the standard. The adoption of section 1582 will also require the adoption of sections 1601 "Consolidated Financial Statements" and 1602 "Non-controlling Interest". ISR is currently assessing the impact of the standard.

Consolidated Financial Statements and Non-Controlling Interests

In 2009 two new standards, 1601 "Consolidated Financial Statements" and 1602 "Non-controlling Interest", were issued which replace the existing guidance under section 1600 "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective for business combinations occurring on or after January 1, 2011, with early application permitted. ISR is currently assessing the impact of the standard.

Risk Factors

Investors that purchase shares are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of the Company's shares is subject to numerous risk factors. Some of the risks are common to all businesses while many are associated with the oil and gas industry the following information is only a summary of certain risk factors which could affect the Company's future results:

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome.. There is no assurance that expenditures made on future exploration by ISR will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associate with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of ISR will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that ISR will be able to locate satisfactory properties for acquisition or

participation. Moreover, if such acquisitions or participations are identified, ISR may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

ISR attempts to minimize exploration, development and production risks by utilizing a high-end technical team with extensive experience and multidisciplinary skill sets to assure the highest probability of success in its drilling efforts. Our collaboration of a team of seasoned veterans in the oil and gas business, each with a unique expertise in the various upstream to downstream technical disciplines of prospect generation to operations, provides the best assurance of competency, risk management and drilling success. A full cycle economic model is utilized to evaluate all hydrocarbon prospects. Detailed geological and geophysical techniques are regularly employed including 3D seismic, petrography, sedimentology, petrophysical log analysis and regional geological evaluation. ISR utilizes not only the publicly available sources of subsurface data and information, but also employs its own proprietary data set of rock core and drill cuttings descriptions to enhance the quality and probability of success of its internally generated plays and prospects. Where possible prospects have multi-zone potential and activity is focused in regions where ISR's expertise and experience can provide a competitive advantage.

Reserve estimates of economically recoverable natural gas and crude oil reserves (including natural gas liquids) and the future net cash flows there from are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operation expenses. All of these estimates may vary from actual results. Estimates of the recoverable natural gas and crude oil reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected there from, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Each year, a firm of independent engineers evaluates a significant portion of proved and probable reserves. At December 31, 2009, 100 percent of the reserves of ISR were evaluated by Paddock, Lindstrom & Associates Ltd.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008, 2009 and are continuing in 2010, causing a loss of confidence in the broader United States, European and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of ISR. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of ISR's oil and gas reserves. ISR might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in ISR's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition material decline in prices from historical average prices could limit ISR's borrowing base, therefore reducing the bank credit available to ISR, and could require that a portion of any existing bank debt of ISR be repaid.

In addition to establishing markets for its oil and natural gas, ISR must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by ISR will be affected by numerous factors beyond its control. ISR will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by ISR. The ability of ISR to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. ISR will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and may other aspects of the oil and natural gas business.

The Company's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. With the Company's production heavily weighted to natural gas, changes to natural gas prices have the most material effect on its cash flow. Prices for natural gas and crude oil have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil producing regions, which are beyond the control of the Company. Prices received from production in Canada also reflect changes in the Canadian/US currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Company's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

Substantial Capital Requirements; Liquidity

ISR's cash flow from its production and sales of petroleum and natural gas may not, at all times be sufficient to fund its ongoing activities. From time to time, ISR may require additional financing in order to carry out its oil and acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause ISR to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If ISR's revenues from its production of petroleum and natural gas decrease as a result of lower oil and natural gas prices or otherwise, it may affect ISR's ability to expend the necessary capital to replace its reserves or to maintain its production. If ISR's funds from operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to ISR.

ISR's lenders will be provided with security over substantially all of the assets of ISR. If ISR becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell ISR's properties. The proceeds of any such sale would be applied to satisfy amounts owed to ISR's lenders and other creditors and only the remainder, if any, would be available to ISR.

The Company monitors and updates its cash projection models on a regular basis which assists in the timing decision of capital expenditures. Farm-outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that we wish to hold a lesser working interest position. Equity, if available and if on reasonable terms, may be utilized to help fund our capital program.

Access to Capital

Access to capital has become limited during these times of economic uncertainty. To the extent the external sources of capital become limited or unavailable; ISR's ability to make the necessary capital investments to maintain or expand oil and gas reserves may be impaired.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry will not be changed in a manner which adversely affects the Company or its shareholders.

Although the Company has no control over these regulatory risks, it continuously monitors changes in these areas by participating in industry organizations and conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on the Company's financial and operating results.

Credit Exposure

Recent economic conditions have increased the risk that certain counterparties for our oil and gas sales and our joint venture partners may fail to pay. We mitigate these increased risks through diversification and a review process of the credit worthiness of our counterparties, but still assumes customer credit risk associated with natural gas and crude oil sales, financial hedging transactions and joint venture participants.

ISR's policy to mitigate credit risk associated with product sales is to maintain marketing relationships with large, established and reputable purchasers that are considered creditworthy. ISR has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected within two to three months of the joint venture bill being issued to the partner. ISR attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital and operating expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint venture partners. Joint venture receivables are from partners in the petroleum and natural gas industry who are subject to the risks and conditions of the industry. Significant changes in industry conditions and risks that negatively impact partners' ability to generate cash flow will increase the risk of not collecting receivables. ISR does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment or may be able to register security on the assets of joint venture partners.

Health, Safety and Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditure and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Company believes that it will be immaterial compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to

climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established there under to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called “greenhouse gases”. The Company’s exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject the Company to possible future legislation regulating emissions of greenhouse gases, such as the Government of Canada’s proposed Clean Air Act of 2006 and Alberta’s recently enacted Climate Change and Emissions Management Act. The direct or indirect costs of these regulations may adversely affect the expected business of the Company.

Insurance

ISR’s involvement in the exploration for and development of oil and gas properties may result in ISR becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although ISR has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, ISR may elect not to obtain insurance to deal with specific risks due to the high premiums associate with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to ISR. The occurrence of a significant event that ISR is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on ISR’s financial position, results of operations or prospects.

Competition

ISR actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel resources than ISR. ISR’s competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Certain of ISR’s customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect ISR’s ability to sell or supply oil or gas to these customers in the future. ISR’s ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Additional Information

Additional information regarding International Sovereign Energy Corp. and its business and operations, including the annual information form (“AIF”) is available on the Company’s profile at www.sedar.com. Information can also be obtained by contacting the Company at International Sovereign Energy Corp., 1750, 801 – 6th Avenue S.W., Calgary, Alberta T2P 3W2 or by assessing the website at www.isove.com.