International Frontier Resources Corporation
Management's Discussion and Analysis
2009 Annual and Fourth Quarter Results

International Frontier Resources Corporation is engaged in the exploration for and development of petroleum and natural gas reserves in the Central Mackenzie Valley ("CMV"), Northwest Territories, Canada. The Company does not operate its properties in the CMV therefore the timing of operations and capital expenditures are determined by the operator, Husky Oil Operations Limited

The following is management's discussion and analysis ("MD&A") of International Frontier Resources Corporation's ("International Frontier" or "IFR" or "Britcana" or the "Corporation" or the "Company") operating and financial results for the year ended December 31, 2009, as well as information concerning the Company's future outlook based on currently available information. The MD&A has been prepared by management as at April 20, 2010 in accordance with GAAP and should be read in conjunction with the audited consolidated financial statements as at December 31, 2009 and 2008 together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information contained in the Company's annual information form dated December 31, 2009. This MD&A contains forward looking statements, the definitions of which are defined herein.

The MD&A and the annual consolidated financial statements and accompanying notes have been prepared by management and approved by the Audit Committee and the Board of Directors.

The quarterly financial statements have not been reviewed or audited on behalf of the shareholders by the Company's independent external auditors. All financial measures presented in this MD&A Report are expressed in Canadian dollars unless otherwise indicated.

Business Strategy

The principal business of the Corporation is to acquire, develop, exploit and produce oil and natural gas in the Central Mackenzie Valley, Northwest Territories ("CMV"). The Corporation is considered to be a development stage enterprise, as it has yet to generate revenue from its properties in the CMV. The exploration and development of the Corporations CMV properties are dependent on the ability of the Corporation to obtain financing or joint venture partners to assist in financing the Corporations exploration programs.

To date, energy infrastructure, specifically in the form of pipelines to transport natural gas, has not yet reached the CMV. A pipeline to transport oil and other liquid hydrocarbons does exist from Northern Alberta to Norman Wells in the CMV. The Corporation believes that should it make a commercial oil or liquids discovery that it can negotiate transportation in the Norman Wells Enbridge oil pipeline to deliver production to Northern Alberta.

Until a natural gas pipeline is built from Northern Alberta to the CMV there is no commercial method to move natural gas from the region. As a result, it is unlikely that the Corporation will generate any revenue from the production of gas until a pipeline is built.

The Corporation believes that the current lack of gas transportation from the CMV provides it with an opportunity to acquire interests in land that would not be available to it on reasonable terms, if a natural gas pipeline existed. The Corporation's business plan is to acquire oil and natural gas prospective acreage at a lower cost today than would be possible if a gas pipeline existed. There is no certainty that a gas pipeline will be built to tie-in existing or future discoveries in the CMV.

The Corporation plans to review new ventures that if successful will provide cash flow earlier than potential cash flow may be obtained from production in the CMV.

Corporate Update

North Sea

The Company's wholly owned UK subsidiary, Britcana Energy Ltd, has participated in the drilling of five exploration wells in the UK sector of the North Sea. The drilling program resulted in two wells finding non-commercial hydrocarbons and three wells failed to find hydrocarbons. Britcana's cost for the exploration program was $16.5 million. As a result of future wells costing in the range of $50 - $60 million the Company decided that it could no longer fund future drilling in the North Sea and in 2009 a decision was made to sell its UK assets.

On April 9th, 2010 License P.233 (block 15/18a Maria) was sold to Maersk Oil North Sea UK Limited for a consideration of CDN$670,244.

On April 13th, 2010 the Company sold its wholly owned UK subsidiary, Britcana Energy Ltd, to Nexen Petroleum UK Limited for an initial consideration of CDN$3,119,517 and a contingent consideration of US$2,000,000. The contingent consideration consists of US$1,000,000 if there is a joint development, or unitization, of the Nexen et al block 15/23d (North Bugle discovery) and the offsetting Nippon et al block 15/23c. The first payment is due upon the UK authorities approving a field development for blocks 15/23d and 15/23c. The second payment of US$1,000,000 is payable upon first oil sales from the North Bugle development.

In the December 31, 2009 audited financial statements the Company has accounted for the sale of Britcana and License P 233 as discontinued operations with an assigned value of CDN $3,718,620.

Central Mackenzie Valley, NWT

The Company plans to use the North Sea sale proceeds, together with existing cash of approximately $3.8 million, to continue exploring in the Central Mackenzie Valley ("CMV") where the Company holds interests ranging from 8.22% to 25% in 735,000 gross acres (133,830 net acres). The acreage portfolio includes three Significant Discovery Licenses, four Exploration Licenses and three Freehold Parcels.

To date the Company has participated in eight geophysical surveys and in nine exploration wells. Of the nine wells drilled two wells encountered gas and oil, one well encountered sweet gas and six wells were plugged and abandoned. This data, the majority of which is proprietary, has provided the Company with a very good understanding of the geological framework of this newly discovered hydrocarbon province.

Significant Discovery Licenses
Summit SDL 140 – 8.2112% (no expiry)
Stewart SDL 138 & 139 – 8.2112% (no expiry)
TDL M-38 included within Stewart SDL – 25% (no expiry)
Operator – Husky Oil Operations Limited

The Company's first discovery in the CMV was located on EL-397, the Summit Creek B-44 well production tested at a rate of 20 MMCF/D and 6,300 barrels of 55 degree API oil from two Devonian age formations.
As a result of this discovery a Significant Discovery License (SDL 140) was awarded covering an area of 11,070 acres. In a report dated July 2008 McDaniel's and Associates assign the following contingent resource estimates for the Company's interest in the Summit SDL 140:

Best Case: 3.1 BCF (gas) + 499,000 barrels (oil)
High Case: 13.4 BCF (gas) + 2.2 million barrels (oil)

The Company's second discovery in the CMV was also located on EL-397; the Stewart Lake L-52 well drill-stem tested 5 MMCF/D from two Cretaceous age formations. As a result of this discovery SDL's 138 & 139 were granted. The SDL area includes TDL Freehold parcel M-38 resulting in a mapped SDL area of 15,918 acres. In a report dated July 2008 McDaniel's & Associates assign the following contingent resource estimates for the Company's interest in the Stewart SDL's and TDL parcel M-38;

Best Case: 5.2 BCF (gas)
High Case: 15.8 BCF (gas)

In 2010, the contingent resource estimate for the Stewart SDL's was adjusted by the Company to take into account that its working interest in TDL M-38 was recently increased from 15% to 25%.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources identified in the McDaniel report.

EL-423
IFR- 15%
Area – 226,500 acres (33,975 net)
Work Commitment - $24.8 million (fulfilled)
Expiry – May 2010
Operator- Husky Oil Operations Limited

In 2008/09 the Company participated for its 15% interest in the drilling of the Dahadinni and Keele River exploration wells. Unfortunately the Dahadinni well did not reach total depth and its primary objective, the Devonian Formation, was not penetrated. The Keele River well tested a shallow Cretaceous oil prospect, the well did not encounter hydrocarbons and it was abandoned. The Company's share of the two-well program was $9,648,505. This amount was impaired and was transferred to the full cost pool during 2009.

EL-441
IFR – 13.40%
Area – 218,500 acres (29,280 net)
Work Commitment - $10.5 million ($2M fulfilled)
Expiry - May 10, 2011.
Operator – Husky Oil Operations Limited

In January 2010 the Department of Indian and Northern Affairs Canada granted approval to extend the primary term of EL-441from May 10, 2010 to May 10, 2011.

The Company has restricted cash securing a letter of credit in the amount of $266,365 which amount represents the Company's share of the remaining work deposit on EL-441. The letter of credit is refundable on the basis of a one-dollar refund for every four-dollars of qualified allowable expenditures incurred. There were no capital expenditures incurred on EL-441 in 2009.

EL-443
IFR – 25%
Area – 227,750 acres (56,937 net)
Work Program - $4.8 million
Expiry – May 10, 2012
Operator – Husky Oil Operations Limited

In January 2010 the Department of Indian and Northern Affairs granted approval to extend the primary term of EL-443 from May 10, 2011 to May 10, 2012.

The Company has restricted cash securing a letter of credit in the amount of $305,555, which amount represents the Company's share of the work deposit on EL-443. The letter of credit is refundable on the basis of a one-dollar refund for every four-dollars of qualified allowable expenditures incurred. The Company did not incur any capital expenditures on EL-443 in 2009.

TDL Freehold Lands

IFR- 25%
Area – 35,000 acres (8,750 net)
Work Program – Nil
Operator – Husky Oil Operations Limited

In Q1 2010 two partners elected to not pay their respective share of the annual shut-in royalty payment on TDL freehold parcel M-37 as well as their share of annual rentals on TDL freehold parcels M-37, M-38 and M-39. In March 2010 the Company and Husky reached an agreement to fund the costs of the forfeited TDL Freehold interests on a Husky 75% - IFR 25% basis.

Subsequent to year end TDL parcels M-32, M-33, M-34 and M35 were relinquished. Other than annual rentals the Company did not incur any significant capital expenditures on the TDL freehold lands in 2009.

EL-445

IFR-25%
Area – 206,000 acres (51,620 net)
Work Program - $1.1 million
Operator – B.G. International

The Company has restricted cash securing a letter of credit in the amount of $68,750 which amount represents the Company's share of the work deposit on EL-445. The Company does not intend on completing the work program on the License, as a result the work deposit will be forfeited in May 2011.

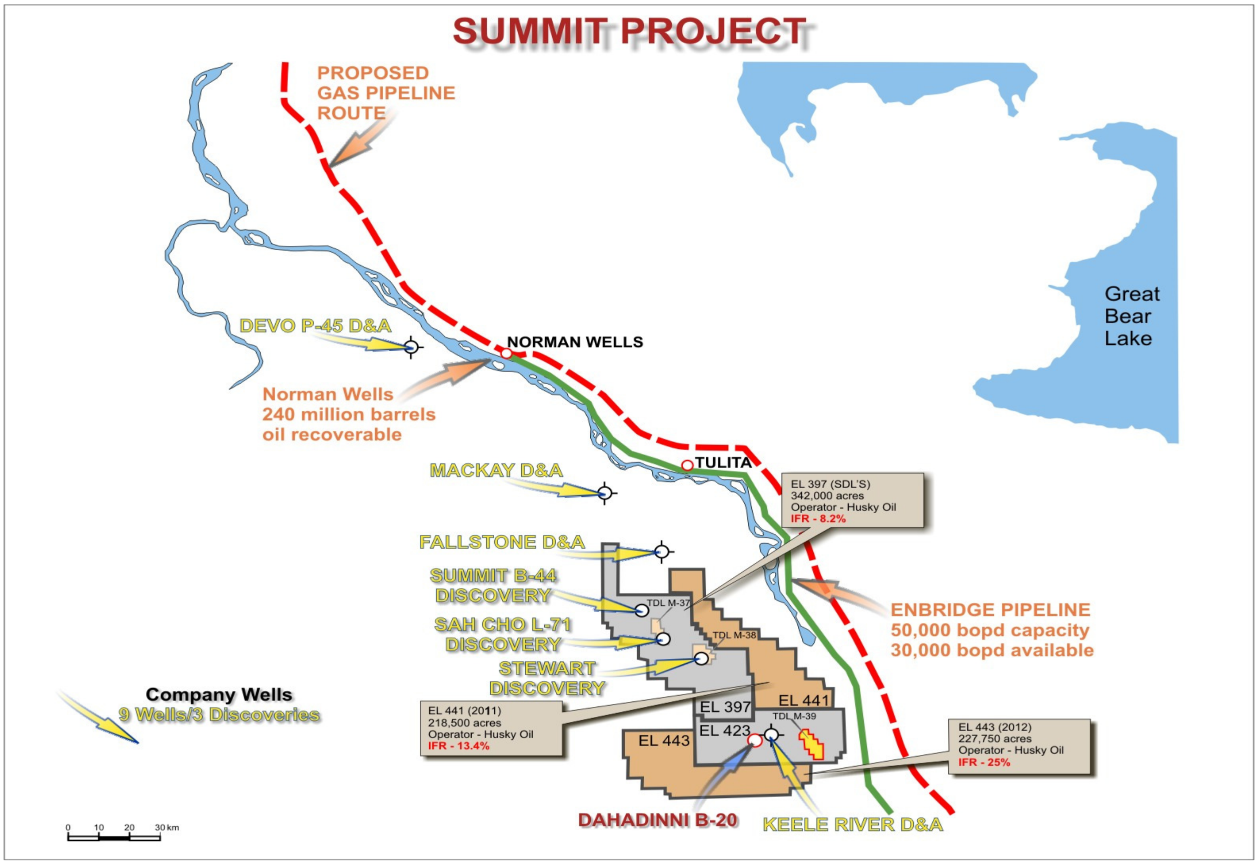
Summary – Central Mackenzie Valley, NWT

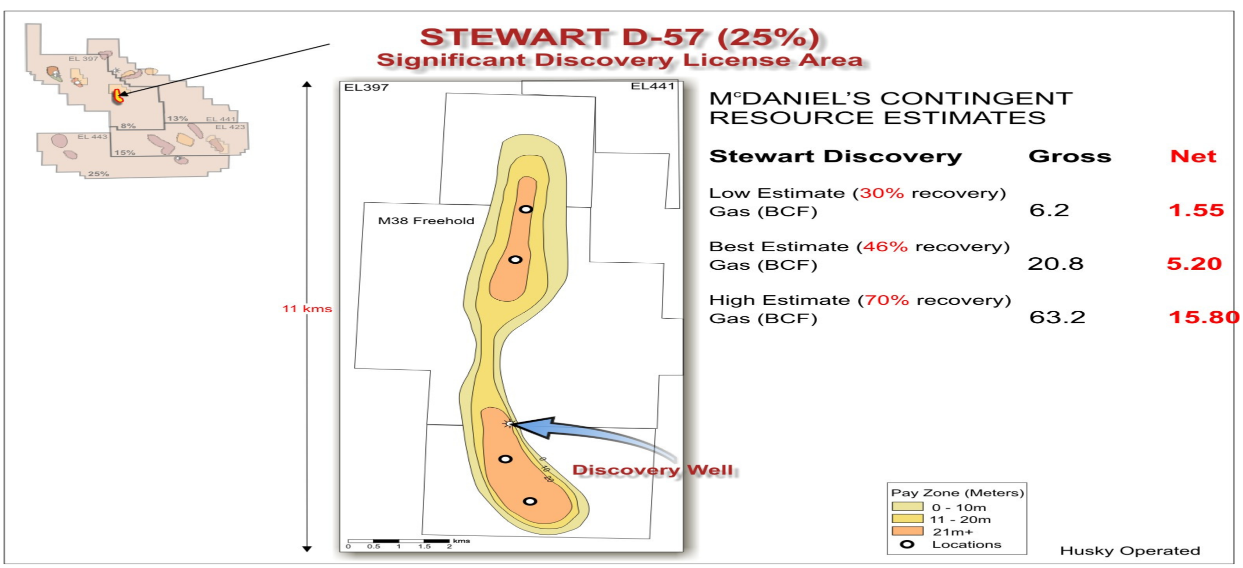
Total capital expenditures in the CMV to date are approximately $175 million (gross) of which the Company's share is $28.5 million. The information obtained from proprietary seismic and drilling data has allowed the operator to high-grade areas that are prospective for oil, gas/condensate and dry gas**.** The areas that are prospect for oil have been prioritized for future seismic and drilling programs. Area's that are prospective for gas will be re-visited when there is more clarity on the Mackenzie Gas Pipeline.

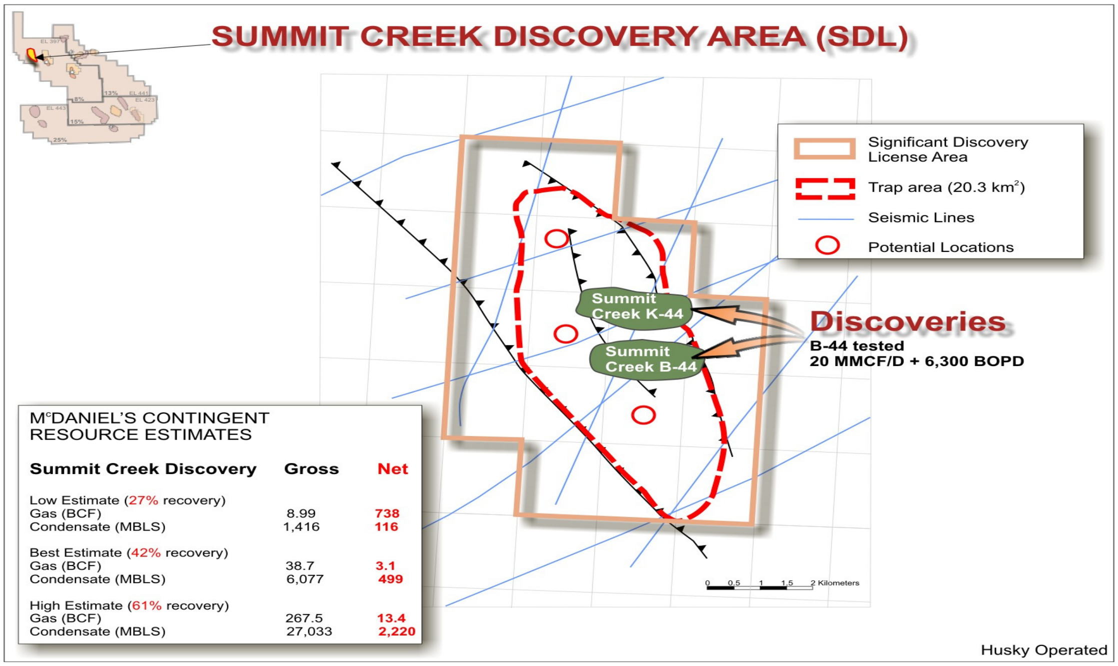
On December 29th, 2009 the Joint Review Panels ("JRP") issued its report on the Mackenzie Valley Gas Pipeline. The report supports construction of the pipeline subject to certain recommendations included in the report. In the Company's opinion not all of the JRP recommendations will be accepted by the National Energy Board ("NEB") or the proponents of the pipeline. The next step in the approval process involves the NEB holding a series of meetings with the proponents and other stakeholders. As part of reaching its decision on the Mackenzie Gas Pipeline the NEB will decide to do one of the following;

1. adopt the JRP's recommendation;
2. adopt the JRP's recommendation with modifications, or;
3. reject the overall recommendation contained in the JRP report.

The National Energy Board is expected to issue its decision on the Mackenzie Gas Pipeline in Q4, 2010.


SUMMIT PROJECT
PROPOSED GAS PIPELINE ROUTE
Great Bear Lake
DEVO P-45 D&A
NORMAN WELLS
Norman Wells 240 million barrels oil recoverable
MACKAY D&A
TULITA
EL 397 (SDL'S) 342,000 acres Operator - Husky Oil IFR - 8.2%
FALLSTONE D&A
SUMMIT B-44 DISCOVERY
SAH CHO L-71 DISCOVERY
STEWART DISCOVERY
TDL M-37
TDL M-38
TDL M-39
ENBRIDGE PIPELINE 50,000 bopd capacity 30,000 bopd available
Company Wells 9 Wells/3 Discoveries
EL 441 (2011) 218,500 acres Operator - Husky Oil IFR - 13.4%
EL 397
EL 441
EL 423
EL 443
EL 443 (2012) 227,750 acres Operator - Husky Oil IFR - 25%
DAHADINNI B-20
KEELE RIVER D&A
0 10 20 30 km


STEWART D-57 (25%)
Significant Discovery License Area
EL397
EL441
M38 Freehold
11 kms
Discovery Well
M^{c}DANIEL'S CONTINGENT RESOURCE ESTIMATES
Stewart Discovery Gross Net
Low Estimate (30% recovery) Gas (BCF) 6.2 1.55
Best Estimate (46% recovery) Gas (BCF) 20.8 5.20
High Estimate (70% recovery) Gas (BCF) 63.2 15.80
Pay Zone (Meters)
0 - 10m
11 - 20m
21m+
Locations
Husky Operated


SUMMIT CREEK DISCOVERY AREA (SDL)
Significant Discovery License Area
Trap area (20.3 km²)
Seismic Lines
Potential Locations
Summit Creek K-44
Summit Creek B-44
Discoveries
B-44 tested
20 MMCF/D + 6,300 BOPD
McDANIEL'S CONTINGENT RESOURCE ESTIMATES
Summit Creek Discovery Gross Net
Low Estimate (27% recovery)
Gas (BCF) 8.99 738
Condensate (MBLS) 1,416 116
Best Estimate (42% recovery)
Gas (BCF) 38.7 3.1
Condensate (MBLS) 6,077 499
High Estimate (61% recovery)
Gas (BCF) 267.5 13.4
Condensate (MBLS) 27,033 2,220
Husky Operated

North Sea UKCS

Bowmore Area – License P1465 (blocks 15/24a, 15/23c, 15/28a & 15/29e)
Britcana (IFR) – 10%
Operator – Nippon Oil Exploration and Production U.K. Limited

License P 1465 was awarded in the UKCS 24th licensing round. The award was made on April 1, 2007 as a traditional license on the basis of an agreed work program for a four year term comprising:

- Obtain 610 sq km of 3D seismic (completed)
- Reprocess 385 sq km of 3D seismic (completed)
- Complete AVO studies (completed)
- Drill one firm well to test the Upper Jurassic (completed with 15/24a-9 well)
- Drill one firm well to test the Paleocene (outstanding)
- Drill two contingent wells, one to test the Jurassic and one to test the Paleocene. Both wells are contingent on success of the two firm wells (outstanding).

In Q3/2009 the Company's wholly owned U.K. subsidiary, Britcana Energy Ltd., participated for its 10% working interest in the Bowmore – Alpha 15/24a-9 Jurassic test well. The well was drilled and cased to a depth of 14,891 feet and rig released in September 2009. The well has been suspended as a "tight hole". The Company's share of costs to drill the 15/24a-9 well was $5,288,845.

In April 2010 the Company sold Britcana Energy Ltd. to Nexen Petroleum UK Ltd. for the following consideration;

- Initial consideration of CDN $3,119,517.
- One million US$1,000,000 on approval by the UK Department of Energy and Climate Change of a Field Development Plan for a joint or unitized development of the Bugle Field between the licensees of Block 15/23c (P.1465) and 15/23d (P.815); and
- One million US Dollars $1,000,000 on the sale of the first lifting of hydrocarbons attributable to Nexen's (Britcana's) participation in such a joint or unitized development.

License P.233 (Maria Block 15/18a)
Britcana (IFR) – 8.33%
Operator – Petro-Canada U.K. Limited

In April 2010 Britcana Energy Ltd sold its 8.33% interest in License P. 233 to Maersk Oil UK Limited for a consideration of CDN $670,244.

Alderson – Brooks Area Alberta

IFR – 100%

The Company operates five producing oil wells and an oil battery located in the Alderson area of southern Alberta. The wells produce approximately 30 BOPD of 30 degree API oil from the Mannville Reservoir. The Company acquired the Alderson property to conduct a pilot program using the Sidox oil production enhancement and water reduction technology.

Liquidity, capital resources and financing activities

Working Capital

At December 31, 2009 cash and cash equivalents were $4,099,740 (December 31, 2008 $9,081,465), and working capital was $7,865,635 (December 31, 2008 - $9,272,675). At December 31, 2009 the Company had restricted cash securing letters of credit in the amount of $640,670; the letters of credit secure refundable work deposits on the Company's Northwest Territories Exploration Licenses. At December 31, 2009 the Company set up a provision for EL-445 in the amount $68,750 as this license will expire in May 2011 and the deposit of $68,750 will be forfeited.

The increase in working capital at December 31, 2009 is a result of discontinued operations of $3,789,760 related to the sale of North Sea operations in 2010 mitigated by a decrease in cash from capital expenditures of $5,135,720 incurred in the North Sea and $357,420 incurred in the Northwest Territories. For the year ended December 31, 2009 the Company used cash flow from operations of $395,495, used cash for investing activities of $4,586,230 resulting in a net cash decrease of $4,981,725.

On April 13, 2010 the Company closed the sale of its 8.33% interest in U.K. License P.233 (Maria block 15/18a) and the sale of its 100% shareholding in its wholly owned U.K. subsidiary Britcana Energy Ltd. for a total consideration of $3,789,760 CAD. Working capital at April 20, 2010 was approximately $7,630,000.

Future Capital Requirements

The Corporation regularly forecasts its capital needs on an annual, quarterly and monthly basis. The Corporation's current internally generated cash flows do not provide sufficient capital for the Corporation's current exploration plans. Historically, the Corporation has relied on proceeds from the sale of its Common Shares to fund its operations. In order to accelerate the Corporation's current exploration programs the Corporation may require additional capital. The timing, pace, scope and amount of the Corporation's capital expenditures is largely dependent on the operators capital expenditure program(s) and the availability of capital to the Corporation.

The Corporation may obtain funds for future capital investments from strategic alliances with other energy or financial partners, the issuance of additional Common Shares, preferred shares or debt securities, project financing, sale of property interests, or other arrangements, all of which may dilute the interest of the Corporation's existing shareholders or the Corporation's interest in the specific project financed. The Corporation may change the allocation of capital among the categories of anticipated expenditures depending upon future events that the Corporation cannot predict. For example, the Corporation may change the allocation of its expenditures based on the actual results and costs of future exploration, appraisal, development, production, property acquisition and other activities. In addition, the Corporation may have to change its anticipated expenditures if costs of placing any particular discovery into production are higher, if the field is smaller or if the commencement of production takes longer than expected.

In the management of capital, the Company includes shareholders' equity (excluding accumulated other comprehensive income (loss), cash and cash equivalents, marketable securities and short term portion of restricted cash less accounts payable in the definition of capital. Management reviews its capital requirements on an ongoing basis and believes that its approach, given the relative size of the Company is reasonable. As at December 31, 2009, the Company's capital as defined above was approximately $24,060,055 (December 31, 2008 – $43,848,820).

Due to current economic conditions it may be difficult for the Company to secure equity financing at the present time. The Corporation has a number of options available to it if existing working capital does not cover future capital expenditures including, but not limited to, i) revising its capital expenditure plans ii) selling a partial or 100% interest in a property to a third party, iii) obtain joint venture financing from a third party, iv) obtaining debt financing, or a combination of these possible steps.

Annual Results

The following table summarizes results for the years 2009, 2008, and 2007.

	2009	2008	2007
Statement of operations			
Sales volumes - BOE/ day (Canada)	35	40	38
Production volumes - BOE/ day (Canada)	36	39	38
Oil revenues, net (Canada)	$ 603,235	$ 970,060	$ 607,490
Interest income from continuing operations	$ 46,950	$ 460,895	$ 1,120,040
Net loss and comprehensive loss			
Net loss from continuing operations	$ (7,775,875)	$ (2,722,875)	$ (1,698,360)
Net loss for discontinued operations	$ (6,937,575)	$ (1,437,345)	$ (4,385,025)
Net loss and comprehensive loss	$ (14,713,450)	$ (4,160,220)	$ (6,083,385)
Loss per share			
Net loss from continuing operations per share	$ (0.13)	$ (0.05)	$ (0.03)
Net loss from discontinued operations per share	$ (0.12)	$ (0.02)	$ (0.08)
Net loss per share	$ (0.25)	$ (0.07)	$ (0.11)
Cash flow			
Net cash provided (used in)			
Operating activities	$ (395,495)	$ 185,230	$ 428,950
Investing activities	$ (4,586,230)	$ (13,863,595)	$ (7,853,035)
Financing activities	$ -	$ (34,290)	$ 20,887,485
Balance sheet			
Assets			
Property and equipment – continuing operations	$ 11,969,305	$ 20,846,600	$ 15,391,060
Total assets	$ 20,972,600	$ 38,255,075	$ 43,508,205
Working capital	$ 7,865,635	$ 9,272,675	$ 22,407,855
Assets of Discontinued operations			
Cash and cash equivalents	$ 3,660	$ 523,835	$ 2,522,820
Receivables	$ 9,020	$ 92,105	$ 342,210
Property and equipment	$ 3,965,335	$ 5,291,290	$ 2,113,815
	$ 3,978,035	$ 5,907,230	$ 4,978,845

Sales Volumes

- Oil production in 2009 averaged 36 Bbl/day compared with 39 Bbl/day in 2008.
- The decrease in production volumes in 2009 can be attributed to natural reservoir decline.

Gross revenues and royalties

- During 2009 gross oil revenue was $770,810 a decrease of $458,270 or 37.29% as compared to $1,229,080 in 2008 (2007 - $787,020)
- The decrease in oil revenue and royalties paid is the result of a 12.50% decrease in oil price ($59.43 per Bbl in 2009 versus $85.73 per Bbl in 2008 and $56.20 per Bbl in 2007).

- In 2009 the Company paid royalties of $152,610 or 19.80% of gross revenues as compared to $235,100 or 19.13% of gross revenues in 2008, a decrease of 35.09 % (2007 - $164,520 or 20.90% of gross revenues).
- In 2009 the Company paid royalties of $14,965 (2008 - $23,920, 2007 - $15,010) to certain executive officers who are also directors and consultants in accordance with the Company's Royalty Incentive Plan.

Interest income

- In 2009 the Company earned interest income from short term investments of $46,950 (2008 - $460,895).
- The decrease in interest income in 2009, as compared to the same period in 2008, is due to a decrease in funds invested of $8,562,980 (from $8,933,450 in 2008 to $1,011,135 at December 31, 2009) coupled with a decrease in the average interest rate earned of 1.15% (from 1.30% in 2008 to 0.15% at December 31, 2009).

Field operating costs

- In 2009 operating expenses were $333,315 a decrease of $42,830 or 11.39% as compared to operating expenses incurred in 2008 of $376,145 (2007 – $508,025).
- Operating costs per Bbl remained relatively constant averaging $25.70 per Bbl as compared to $26.24 per Bbl in 2008 (2007 - $36.28 per Bbl).

Depletion and depreciation

Depletion, depreciation and impairments at December 31, 2009 and 2008 consist of the following;

December 31, 2009

Depletion, depreciation and impairments	Canada	Discontinued Operations- U.K	Total
Depletion of natural gas properties	$ 669,325	$ -	$ 669,325
Impairment of natural gas properties	8,561,845	6,664,380	15,226,225
Amortization of Sidox license	5,000	-	5,000
Depreciation of equipment	3,810	-	3,810
	$ 9,239,980	$ 6,664,380	$ 15,904,360

December 31, 2008

Depletion, depreciation and impairments	Canada	U.K	Total
Depletion of natural gas properties	$ 424,215	$ -	$ 424,215
Impairment of natural gas properties	3,796,325	1,435,375	5,231,700
Amortization of Sidox license	5,000	-	5,000
Depreciation of equipment	4,540	-	4,540
	$ 4,230,080	$ 1,435,375	$ 5,665,455

- Depletion of oil and gas properties for the year ended December 31, 2009 was $669,325 or $51.61 per Bbl, an increase of $245,110 or $22.06 per Bbl as compared to $424,215 or $29.55 per Bbl for the same period in 2008.
- The increase in depletion was due to an increase in the depletable net cost base in the amount of $9,648,505 ($8,615,245 at December 31, 2008) as a result of the Company writing off drilling costs incurred on the Dahadinni and Sah Cho wells located in the Northwest Territories
- At December 31, 2009 an impairment test was performed which calculates the amount by which the carrying amount of capitalized costs related to producing properties exceeds the fair value of the reserves as estimated by the Company's reservoir engineers at December 31, 2009. As a result a $8,561,840 (2008 - $3,796,330) impairment charge of petroleum and natural gas assets has been recorded as part of depletion to reflect the excess carrying amount of assets over fair value of future reserves in Canada.

- In 2009, the Company recognized an impairment expense of $6,664,380 (2008 - $1,435,375) for dry hole costs and G&A expenses incurred in the North Sea. As at December 31, 2009, no additional impairment was identified with respect to the unproved properties
- The carrying value of properties in the exploration stage in the Northwest Territories of $10,072,160 (December 31, 2008 - $19,431,260) and in the North Sea of $7,223,925 (December 31, 2008 - $5,291,290) have been excluded from the full cost pool at December 31, 2009. These properties were evaluated at December 31, 2009 and it was determined that no additional costs were required to be included in the carrying amount of capitalized costs for purposes of calculating depletion and impairment.

Accretion of asset retirement obligation

- Accretion of asset retirement obligations at December 31, 2009 were $48,935, an increase of $16,775 compared to $29,450 in 2008.
- Accretion of asset retirement obligations for the three months ended December 31, 2009 was $12,645 consistent with $12,365 in Q-3 2009.

General and administrative expenses

	2009	2008	2007
Investor relations	$ 60,110	$ 36,880	$ 107,180
Filing and transfer fees	21,535	26,340	39,310
Accounting and legal	105,760	123,765	176,785
Consulting fees - gross	310,640	332,010	446,195
Consulting fees - capitalized	(130,950)	(116,600)	(154,350)
Rent and office costs	190,660	213,245	251,180
Part 12.6 Tax	-	7,820	-
	$ 557,755	$ 623,460	$ 866,300

- In 2009 general and administrative expenses decreased by $65,705 or 10.54% to $557,755 as compared to $ 623,460 in 2008.
- In 2008 and 2009 the Company adopted certain measures to reduce G&A expenses.

Stock based compensation

- Stock based compensation costs of $256,820 were calculated using the Black Scholes model for options granted in the second quarter of 2009.
- There were no stock options issued or exercised in the three months ended December 31, 2009, therefore, no stock based compensation costs were booked in this period

Net loss

For the year ended December 31, 2009 the Company recorded a consolidated net loss of $14,713,450 ($0.25 loss per share).

Net earnings (loss):	2009	2008	2007
Net loss from continuing operations	$ (7,775,875)	$ (2,722,875)	$ (1,698,360)
Net loss from discontinued operations	(6,937,575)	(1,437,345)	(4,385,025)
Consolidated net loss	$ (14,713,450)	$ (4,160,220)	$ (6,083,385)
Loss per share			
Continuing operations	$ (0.13)	$ (0.05)	$ (0.03)
Discontinued operations	$ (0.12)	$ (0.02)	$ (0.08)
Loss per share	$ (0.25)	$ (0.07)	$ (0.11)

- For the year ended December 31, 2009 the loss before tax increase in Canada was due to an impairment of oil and gas properties in the Northwest Territories in the amount of $8,561,840, coupled with a $319,875 decrease in net revenues
- The loss from discontinued operations is represented by a net loss from U.K. operations at December 31, 2009 of $3,709,005 and loss booked on the impairment of assets of discontinued operations of $3,228,570

Financial Instruments

As disclosed in Note 3 to the consolidated financial statements, the Company holds various forms of financial instruments. The nature of these instruments and the Company's operations expose the Company to interest rate risk, foreign exchange risk, fair value risk and industry credit risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

a) Fair value of financial assets and liabilities: The Company's financial instruments as at December 31, 2009 and 2008 include cash and cash equivalents, trade accounts receivable, restricted cash and trade accounts payable. The fair values of trade accounts receivable and trade accounts payable approximate their carrying amounts due to their short terms to maturity. The cash and cash equivalents and the restricted cash balances are equal to their fair values.

	2009		2008	
	Carrying Value ($)	Fair Value ($)	Carrying Value ($)	Fair Value ($)
Financial assets:				
Receivables	$ 144,295	$ 144,295	$ 62,590	$ 62,590
Total financial assets	$ 144,295	$ 144,295	$ 62,590	$ 62,590
Financial liabilities				
Payables and accruals	$ 212,575	$ 212,575	$ 1,204,280	$ 1,204,280
Total financial liabilities	$ 212,575	$ 212,575	$ 1,204,280	$ 1,204,280

The Company classifies the fair value of financial instruments held for trading according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

At December 31, 2009 cash and cash equivalents and restricted cash have been classified as Level 1.

b) **Credit risk:** Substantially all of the accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Though, the Company markets its oil to only one marketer revenues are not significant so that the exposure to the Company is minimized. Management does not believe that there is significant credit risk arising from any of the Company's customers or partners, as substantially all amounts outstanding at December 31, 2009 have been received subsequent to period end. The maximum exposure to loss arising from accounts receivable at any given time is equal to their total carrying amounts on the balance sheet.

Total receivables:	0 to 30 days	31 to 60 days	61 to 90 days	Greater than 90 days
$ 144,295	$ 80,595	$ -	$ -	$ 63,700

c) **Interest rate risk:** The Company is exposed to interest rate cash flow risk to the extent the changes in market interest rates will impact the Company's interest rate price risk. In addition, the Company is also exposed to interest rate risk to the Canada Revenue Agency for interest on unexpended funds on the Company's flow through share obligations from February 1 to December 31 of each year. The Company does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. A 1% increase or decrease in interest rates would have had no material impact on the cash flow of the Company during the period ended December 31, 2009.

d) **Foreign currency risk:** The Company is exposed to foreign currency risk as the Company holds cash and cash equivalents on hand that are denominated in British pounds and is exposed to foreign currency fluctuations on its operations in the United Kingdom as these are denominated in British pounds. At December 31, 2009, the carrying amount of the Company's foreign currency denominated net monetary assets was approximately C$43,735 Assuming all other variables remain constant, a fluctuation of one cent in the exchange rate of the Canadian dollar to the British pound would not result in a material change in income

e) **Liquidity risk:** Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's objective in managing liquidity risk is to ensure that it has sufficient resources available to meet its liabilities when due. At December 31, 2009, the Company's accounts payable and accrued liabilities were $212,575 all of which are due for payment within normal terms of trade which is generally between 30 and 60 days. The Company regularly reviews its accounts payable balances and follows up on amounts past due. The Company's financial liabilities are summarized below:

Total payables:	0 to 30 days	31 to 60 days	61 to 90 days	Greater than 90 days
$ 212,575	$ 182,320	$ 1,215	$ 55	$ 28,985

Investing Activities

	Twelve months ended December31,					
	2009			2008		
	Canada	Discontinued Operations	Total	Canada	Discontinued Operations	Total
Cash Expenditures	$ 811,130	$ 5,409,380	$ 6,220,510	$ 9,676,575	$ 4,612,850	$ 14,289,425
PNG Recoveries	(453,710)	(273,660)	(727,370)	-	-	-
	$ 357,420	$ 5,135,720	$ 5,493,140	$ 9,676,575	$ 4,612,850	$ 14,289,425

- Capital expenditures in 2009 were $5,493,140 (2008 – $14,289,430) of which $357,420 or 5% (2008 – 68%, 2007 – 43%) is related to exploration activities in the Northwest Territories and $5,135,720 or 95% (2008 – 32%, 2007 – 57%) is related to exploration activities of discontinued operations in the U.K. North Sea.
- In the North Sea capital expenditures of $5,288,845 relate to costs incurred for the drilling of the Company's 10% share of the Bowmore – Alpha 15/24a-9 well.

Obligations

- The Company is party to an agreement to lease its premises until December 31, 2011. The annual rent of premises consists of a minimum rent payment of $53,400 plus occupancy costs to the end of the lease.
- The Company has established a Royalty Incentive Agreement for employees, consultants and senior executives that are also directors. Under the plan, the compensation committee issues units on an annual basis to employees, consultants and directors. The units entitle the holder to receive an annual payment based on 2% of the Company's annual production revenue, net of transportation and processing fees. Under the terms of the agreement once the Company has recovered payout of 100% of its cumulative annual capital expenditures the payment to employees, consultants and directors is based on 4% of the Company's annual production revenue less transportation and processing fees.

Related Party Transactions

Certain officers who are directors and consultants provide professional, consulting and management services to the Company and are eligible to receive royalties pursuant to the Company's Royalty Incentive Plan. The amounts paid to officers (directors) and consultants during for the period ending December 31, 2009 are provided below, these costs are included in general and administrative expenses on the consolidated statements of earnings (loss), deficit and comprehensive earnings (loss) at December 31, 2009:

- Compensation paid to executive officers was $109,500 (2008 - $108,000) of which $65,250 (2008 - $66,000) was capitalized to property and equipment for the year ended December 31, 2009.
- Director's fees paid to the Chair of the Company's audit committee were $Nil (2008 - $14,500).
- Legal fees of $17,270 (2008 - $6,310) were paid to a law firm in which a Director is a partner, for services provided in the normal course of business.
- At December 31, 2009 royalties of $11,145 (2008 - $16,745) were paid to officers and consultants pursuant to the Company's Royalty Incentive Plan.
- During the year two directors of the Company were also directors of the Company's 50% owned subsidiary Sidox Chemicals Canada Ltd.

Summary of Fourth Quarter Results

Selected financial information:

	Three months ended, December 31, 2009	Three months ended, December 31, 2008	Three months ended, September 30, 2009	Three months ended, September 30, 2008
Statement of operations				
Sales volumes - BOE/ day (Canada)	36	42	35	33
Production volumes - BOE/ day (Canada)	34	38	36	39
Oil revenues, net (Canada)	$ 180,885	$ 143,995	$ 162,280	$ 255,490
Interest income from continuing operations	$ 46,950	$ 77,685	$ 12,050	$ 79,070
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (1,942,045)	$ (2,619,245)	$ (1,682,195)	$ 101,980
Net loss for discontinued operations	$ (3,505,745)	$ (1,503,285)	$ (198,225)	$ (12,795)
Net earnings (loss) and comprehensive loss	$ (5,447,790)	$ (4,122,530)	$ (1,880,420)	$ 89,185
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.04)	$ (0.02)	$ (0.03)	$ 0.002
Net loss from discontinued operations per share	$ (0.11)	$ (0.03)	$ (0.00)	$ (0.00)
Net loss per share	$ (0.15)	$ (0.05)	$ (0.03)	$ 0.002
Cash flow				
Net cash provided (used in)				
Operating activities	$ (146,220)	$ 26,495	$ (167,620)	$ 132,295
Investing activities	$ 188,515	$ (579,460)	$ (3,885,875)	$ (15,256,680)
Financing activities	$ -	$ -	$ -	$ (84,290)

Sales Volumes

- Sales volumes for the three months ended December 31, 2009 were 42 Bbl/day an increase of 27.27% as compared to 33 Bbl/ day for the three months ended September 30, 2009 and consistent with 39 Bbl/day for the three months ended June 30, 2009.
- Production volumes for the three months ended December 31, 2009 were 34 Bbl/day as compared to 36 Bbl/day for the three month ended September 30,2009 and 42 Bbl per day for the fourth quarter 2008

Gross revenues and royalties

- Oil revenue in Q4 was $228,340 an increase of 9.27% compared to Q3 (Q3-2009 - $208,960, Q4-2008 - $202,230).
- In Q4 the Company paid royalties of $43,000 which is consistent with $42,585 in the previous quarter (Q4-2008 - $34,315)
- The increase in oil revenues in the fourth quarter of 2009 is due to slight increase in production volumes coupled with an increase in oil price received in the period.

Interest income

- In Q-4 2009 interest income from short term investments was $380 (Q3-2009 - $12,050, Q4-2008 - $22,740) the decrease was due to decrease in rate received coupled with amount invested.

Field operating costs

- Operating expenses in the fourth quarter were $100,500 or $28.16 per Bbl (Q3-2009 - $48,090 or $14.31 per Bbl, Q4- 2008 - $ 93,320 or $26.89)
- The increase in operating costs was the result of well work-overs and an increase in facility costs at Alderson.

Depletion, depreciation and impairments

Depletion, depreciation and impairments for the three months ended December 31, 2009 and September 30, 2009 respectively consist of the following

December 31, 2009

Depletion, depreciation and impairments	Canada	Discontinued Operations	Total
Depletion of natural gas properties	$ 182,145	$ -	$ 182,145
Impairment of natural gas properties	2,586,025	6,664,380	9,250,405
Amortization of Sidox license	1,250	-	1,250
Depreciation of equipment	865	-	865
	$ 2,770,285	$ 6,664,380	$ 9,434,665

September 30, 2009

Depletion, depreciation and impairments	Canada	Discontinued Operations	Total
Depletion of natural gas properties	$ 230,780	$ -	$ 230,780
Impairment of natural gas properties	3,078,025	-	3,078,025
Amortization of Sidox license	1,250	-	1,250
Depreciation of equipment	920	-	920
	$ 3,310,975	$ -	$ 3,310,975

- Depletion of oil and gas properties for the three months ended December 31, 2009 was $182,145 or $57.42 per Bbl, a decrease of $48,635 or $11.26 per Bbl as compared to $230,780 or $68.68 per Bbl for the third quarter of 2009. The decrease in depletion is due to an increase in reserves as estimated by McDaniel's & Associates at December 31, 2009.
- The increase in depletion and impairment charges in Q4 is due to an increase in the depletable cost base as a result of the Company writing off drilling costs incurred on the Dahadinni and Sah Cho wells located in the Northwest Territories.

General and administrative expenses

Three Months Ended	December 31, 2009	September 30, 2009	December 31, 2008
Investor relations	$ 845	$ 3,365	$ 12,540
Filing and Transfer Fees	$ 1,890	$ 4,705	$ 2,300
Professional Fees	$ 66,490	$ 1,485	$ 93,650
Consulting Fees – gross	$ 84,100	$ 83,000	$ 61,350
Consulting Fees – capitalized	$ (35,400)	$ (35,400)	$ (24,750)
Rent and office Costs	$ 43,040	$ 33,065	$ 28,530
Part 12.6 Tax	$ -	$ -	$ 7,820
	$ 160,965	$ 90,220	$ 181,440

- In Q4 general and administrative expenses were $160,965, an increase of $70,745 or 76.41% as compared with $90,220 in Q3.
- The increase in G&A is due to year end accruals for professional fees at December 31, 2009.

Net loss

Three months ended:	Q-4 2009	Q-3 2009	Q-4 2008
Net loss from continuing operations	$ (2,294,220)	$ (1,682,195)	$ (1,418,245)
Net loss from discontinued operations	(6,764,310)	(198,225)	(1,503,285)
Consolidated net loss	$ (9,058,530)	$ (1,880,420)	$ (2,921,530)
Loss per share			
Continuing operations	$ (0.04)	$ (0.03)	$ (0.02)
Discontinued operations	$ (0.11)	$ (0.00)	$ (0.03)
Loss per share	$ (0.15)	$ (0.03)	$ (0.05)

The increased loss in Q4 as compared with Q3 is a result of the following adjustments.

- An impairment charge on oil and gas properties totaling $5,501,545, consisting of $2,077,410 in the NWT and $3,424,135 in the North Sea resulting in an increase of $2,084,955 in depletion and depreciation expense in Q-4 2009.
- Accrual for year-end audit fees and 51-101 reserve report costs $60,000.
- A recovery of future income taxes of $1,726,140 booked in the third quarter of 2009

Summary of Quarterly Results

The following table summarized the Company's financial and operating highlights for the past eight quarters:

Quarter ended:	March 31, 2008	June 30, 2008	Sept 30, 2008	Dec 31, 2008
Statement of operations				
Sales volumes - BOE/ day (Canada)	46	39	33	42
Production volumes - BOE/ day (Canada)	41	39	39	38
Oil revenues, net (Canada)	$ 268,065	$ 302,510	$ 255,490	$ 143,995
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ 76,880	$ (1,483,490)	$ 101,980	$ (2,619,245)
Net loss for discontinued operations	$ 125,740	$ (47,005)	$ (12,795)	$ (1,503,285)
Net earnings (loss) and comprehensive loss	$ 202,620	$ (1,530,495)	$ 89,185	$ (4,122,530)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ 0.001	$ (0.03)	$ 0.002	$ (0.02)
Net loss from discontinued operations per share	$ 0.002	$ (0.001)	$ (0.00)	$ (0.03)
Net loss per share	$ 0.003	$ (0.03)	$ 0.002	$ (0.05)
Balance Sheet				
Total assets	$49,532,445	$41,857,440	$ 42,763,695	$ 38,255,075
Working capital	$14,452,115	$10,273,020	$ 8,813,135	$ 15,179,905
Refundable Deposits	$ 2,267,175	$ 2,267,175	$ 2,267,175	$ 2,267,175
Funds flow from operations	$ 272,575	$ 133,320	$ 148,400	$ (184,590)

Summary of Quarterly Results

Quarter ended:	March 31, 2009	June 30, 2009	Sept 30, 2009	Dec 31, 2009
Statement of operations				
Sales volumes - BOE/ day (Canada)	35	34	35	36
Production volumes - BOE/ day (Canada)	36	36	36	34
Oil revenues, net (Canada)	$ 110,835	$ 149,235	$ 162,280	$ 180,885
Net earnings (loss) and comprehensive loss				
Net earnings (loss) from continuing operations	$ (99,930)	$ (3,669,530)	$ (1,682,195)	$ (1,942,045)
Net loss for discontinued operations	$ (4,655)	$ 29,615	$ (198,225)	$ (3,505,745)
Net earnings (loss) and comprehensive loss	$ (104,585)	$ (3,639,915)	$ (1,880,420)	$ (5,447,790)
Net earnings(loss) per share				
Net loss from continuing operations per share	$ (0.002)	$ (0.06)	$ (0.03)	$ (0.04)
Net loss from discontinued operations per share	$ (0.00)	$ .0.00	$ (0.00)	$ (0.11)
Net loss per share	$ (0.002)	$ (0.06)	$ (0.03)	$ (0.15)
Balance Sheet				
Total assets	$37,219,740	$33,956,845	$ 29,980,890	$ 20,972,600
Working capital	$10,239,230	$ 9,139,770	$ 4,279,660	$ 7,865,635
Refundable Deposits	$ 1,520,315	$ 925,060	$ 925,060	$ 640,670
Funds flow from operations	$ (75,685)	$ (122,390)	$ (188,805)	$ (146,220)

Other Items

Outstanding shares, options and warrants

The Company's share capital structure is as follows:

As of:	December 31, 2009	April 20, 2010
Common shares outstanding	59,578,965	59,578,965
Options outstanding	3,895,000	3,895,000
Fully diluted	63,473,965	63,473,965

Additional details on the shares, options and warrants outstanding at December 31, 2009 are available in the Notes to the December 31, 2009 audited consolidated financial statements.

International Financial Reporting Standards (IFRS)

IFRS Transition Plan

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. International Frontier Resources will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a transition plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information.

The Company commenced its IFRS transition project in 2008 and has completed the project awareness and engagement phase of the IFRS transition project. The Company`s IFRS transition project consists of three key phases; the scoping and diagnostic phase, the impact analysis and evaluation phase and finally the implementation phase.

Scoping and diagnostic phase

In 2009, the Company made significant progress on its IFRS transition project. The Company is completing the scoping and diagnostic phase in which the Company has performed comparisons of the differences between Canadian GAAP and IFRS, analyzed accounting policy alternatives and drafted its preliminary IFRS accounting policies.

Management has also begun preliminary accounting assessments on key IFRS transition issues. These assessments include Exploration for and Evaluation of Mineral Resources, Property, Plant and Equipment, Impairments of Assets, Decommissioning Liabilities, Intangible Assets and Income Taxes. The Company continues to perform assessments on the remaining IFRS transition issues and has commenced analysis of IFRS financial statement presentation and disclosure requirements.

Impact analysis and evaluation phase

The company is also currently working on the design, planning and evaluation phase. During this phase, items identified in the diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to the Company's business processes or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the Audit Committee of the Board of Directors to review and approve all accounting policy choices as proposed by management.

Implementation phase

This phase involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

Current Status of IFRS Transition Plan

The Corporation conducted preliminary analysis of accounting policy alternatives and began drafting several of its IFRS accounting policies. Broader business process and systems impacts have been considered for significant areas of impact, with internal control requirements taken into account. Process and system changes will be implemented in early 2010 to ensure IFRS comparative data is captured. The Company's IFRS accounting policies are expected to be finalized mid-2010. Quantification of IFRS impacts will then be determined utilizing previously captured data. Communication of impacts to external stakeholders is expected to occur in the latter half of 2010. The Company will continue to update its IFRS transition plan to reflect new and amended accounting standards issued by the International Accounting Standards Board ("IASB").

The Corporation has concluded that the following key issues are expected to have the most significant impact on the company's results of operations, financial position and disclosures:

- Transition on date of adoption of IFRS
- Property, Plant and Equipment ("PP&E"), including;
  - Pre-exploration costs
  - Exploration and Evaluation ("E&E") costs
  - Depletion, depreciation and amortization
  - Impairment testing
- Decommissioning liabilities (known as "asset retirement obligations" under Canadian GAAP)
- Income taxes

Each of these significant impact areas is discussed in more detail below.

Property, Plant & Equipment

- Exploration and evaluation ("E&E") costs - Currently these costs are included in the PP&E balance on the Consolidated Balance Sheet, and include undeveloped land and costs relating to pre-commercial exploration of development. These costs are currently not being depleted. Under IFRS these costs will be moved out of the PP&E balance, and reported separately as E&E assets on the balance sheet. E&E costs will not be depleted but assessed for impairment and unrecoverable costs associated with a specific area will be expensed. When a project is determined to be technically feasible and commercially viable, the costs will be moved to PP&E and depletion will commence.
- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, the Corporation has the option to calculate depletion using a reserve base of proved reserves or both proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. The Corporation has not concluded at this time which method for calculating depletion will be used.
- For the first step of the impairment test under Canadian GAAP, future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for PP&E, impairment testing is currently performed at the country cost centre level, while under IFRS; it will be performed at a lower level, referred to as a cash-generating unit. Under IAS 36 the impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves
- Canadian GAAP prohibits reversal of impairment losses. Under IFRS if the conditions giving rise to impairment have reversed, impairment losses previously recorded would be partially or fully reversed to eliminate write downs recorded. The Company expects to adopt these changes in accounting policy prospectively. At this time, the impact of accounting policy differences related to impairment testing is not reasonably determinable.

Decommissioning liabilities (known as "asset retirement obligations" under GAAP)

- Under Canadian GAAP, the Corporation recognizes a liability for the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in wells and facilities, including an estimate for the timing of the costs to be incurred in future periods. These cash outflows are discounted using a credit-adjusted rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A.
  Under IFRS, these liabilities are known as "decommissioning liabilities" and are included in the scope of IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*. Decommissioning liabilities are calculated at each reporting period using estimate of risk-adjusted future cash outflows discounted using a risk-free rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of DD&A.

Income Tax

- In transitioning to IFRS, the carrying amount of The Company's tax balances will be directly impacted *by the tax effects resulting from changes required by t*he above IFRS accounting policy differences.
- Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009, The Company is still determining the impact of the revised standard on its IFRS transition. Therefore, at this time the income tax impacts of our differences are not reasonably determinable.

Changes to IFRS Accounting Standards

The Company's analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. The Corporation will continue to monitor any new or amended accounting standards that are issued by the IASB, including assessing any impact of the new joint ventures standard that the IASB expects to publish in the first quarter of 2010.

Internal Controls over Financial Reporting

The Company does not anticipate that the transition to IFRS will have a significant impact on either its internal controls over financial reporting, or its disclosure controls and procedures. As the review of The Company's accounting policies is completed, an assessment will be made to determine changes necessary for internal controls over financial reporting. For example, additional controls and review will be implemented as necessary for the IFRS 1 changes such as the allocation of The Company's PP&E as well as the process for reclassifying E&E expenditures from PP&E on transition. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Throughout the transition, The Company will assess stakeholders' information requirements and will ensure that adequate and timely information is provided so that all stakeholders remain apprised.

Education and Training

All of the individuals that are involved in financial reporting under Canadian GAAP have been engaged and involved in the IFRS transition project since 2008, and will continue to be involved in the IFRS transition throughout 2010 and 2011.

Impacts to our Business

The Company does not expect that the adoption of IFRS in 2011 will have a significant impact or influence on its business activities, operations or strategies.

Accounting Policies

Changes in accounting policies and new pronouncements

On January 1, 2009, the Company adopted the following new accounting standards:

- In January 2009, the Emerging Issues Committee ("EIC") of the CICA issued EIC 173, which details guidance on the implications of credit risk in determining 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 the counterparty 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 conclusion of the EIC was effective from the date of issuance of the abstract and did not have any impact on the Company's consolidated financial statements.

- Effective January 1, 2009, the Corporation adopted Section 3064, "Goodwill and Intangible Assets" issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on the Corporation or its Consolidated Financial Statements
- During 2009, amendments were made to Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. See Note 16 for the enhanced disclosures and liquidity risk disclosures. The amendments are consistent with recent amendments to financial instruments disclosure under International Financial Reporting Standards
- In July 2009, the CICA amended CICA Section 3855, "Financial Instruments – Recognition and Measurement", in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and provided that when certain conditions have been met, reclassification of financial assets from the held-for trading and available-for-sale categories into the loans and receivables category is permitted. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. The Company adopted this standard prospectively effective December 31, 2009. The adoption of the amendments of this standard did not have a material impact on the financial statements of the Company.

The Company is assessing the new and revised accounting pronouncements that have been issued that are not yet effective:

- In January 2009, the CICA issued new standards for Business Combinations. This standard is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. This standard replaces Handbook Section 1581 Business Combinations, and harmonizes the Canadian standards with IFRS. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. The adoption of this standard will not have a material impact on the Company's financial statements.

- January, 2009, CICA Handbook Section 1601 – Consolidated Financial Statements was issued which, together with new CICA Handbook Section 1602 – Non-controlling Interests, replaces the former Section 1600 – Consolidated Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of International Financial Report Standards IAS 27 – Consolidated and Separate Financial Statements. Sections 1601 and 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. The Corporation does not anticipate that these sections will have a material impact on its financial statements.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of Canadian generally accepted accounting principles that have a significant impact on the financial results of the Company. Reserve estimates are a key component in the calculation of depletion, depreciation and accretion costs. A change in reserve quantity estimates will result in a corresponding change in DD&A costs. In addition, if capitalized costs are determined to be in excess of the calculated ceiling, which is based on reserve quantities and values, the excess must be written off as an expense. Asset retirement costs are estimated, discounted and carried on the balance sheet as a liability. A change in estimated future asset restoration costs will change the liability on the balance sheet and the amortization of the asset retirement costs included in property and equipment.

Operational and other business risks

Current Economic Conditions

The volatility in the price of oil and natural gas has created a substantially more volatile business environment. These conditions may limit certain of the Company's business activities and it will continue to provide risk for International Frontier's exploration projects.

Need to Replace and Grow Reserves

The future oil and natural gas production of International Frontier, and therefore future cash flows, are highly dependent upon ongoing success in exploring its current and future undeveloped land base, exploiting the current producing properties, and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of International Frontier to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired.

There can be no assurance that International Frontier will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Exploration, Development and Production Risks

Oil and natural gas exploration in the Central Mackenzie Valley, NWT involves a high degree of risk, which even with 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 International Frontier will result in new discoveries of oil and 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 associated 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 International Frontier depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that International Frontier will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participation are identified, International Frontier 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 recover of drilling, completion and operating cost. 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 rate 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, blowouts, 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.

Reserve Estimates

The production forecast and recoverable estimates contained in International Frontier's engineering report are only estimates and the actual production and ultimate recoverable reserves from the properties may be greater or less than the independent estimates of McDaniel & Associates Consultants Ltd. There is no certainty that it will be commercially viable to produce any portion of the contingent resources identified in the December 2008 McDaniel & Associates report.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived thereof, including many factors that are beyond the control of International Frontier. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the assets of International Frontier have been independently evaluated effective December 31, 2009 by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditure, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of International Frontier. Actual production and cash flows derived thereof will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived thereof contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Contingent Resources

The resources assigned to the Company's properties have been classified as contingent. The Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 1 defines contingent resources as quantities of oil and gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status.

- Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulations. If probabilistic methods are used this term reflects a P90 confidence level.
- Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used this term is a measure of the central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean).
- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P10 confidence level.

There is no certainty that a gas pipeline will be constructed to tie-in the Company's contingent resources, nor is there certainty that it will be commercially viable to produce any portion of the contingent resources identified in the McDaniel & Associates contingent resource report date December 2008.

Volatility of Oil and Natural Gas Prices

The operational results and financial condition of International Frontier will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect of the operations, proved reserves, and financial conditions of International Frontier and could result in a reduction of the net production revenue of the Company causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings which might be made available to the Company are typically determined in part by the borrowing base of the reserves of International Frontier. A sustained material decline in prices from historical average prices could reduce the borrowing base of International Frontier, therefore reducing the bank credit available to International Frontier and could require that a portion of such bank debt be repaid.

International Frontier uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed on a quarterly basis for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows.

Operational Hazards and Other Uncertainties

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production faculties, other property and the environment or in personal injury. In accordance with industry practice, International Frontier is not fully insured against all of these risks, nor is all such risks insurable. Although International Frontier will maintain liability insurance, where available, in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event International Frontier could incur significant costs that could have a material adverse affect upon its financial condition. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability and/or cost of such equipment to International

Frontier and may delay exploration and development activities. To the extent International Frontier is not the operator of its oil and gas properties, the Company will be dependent on other operators for timing of activities related to non-operating properties and will be largely unable to direct or control the activities of the operators.

Although property title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of International Frontier which could result in reduction of the revenue received by the Company.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. International Frontier will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than does International Frontier. There can be no certainty that the Company's bid for new acreage in the CMV will successful as the competition for land in the CMV will likely increase if a gas pipeline is constructed.

Key Personnel

The success of International Frontier will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on International Frontier. International Frontier does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of International Frontier are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that International Frontier will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Environmental Risks

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. A breach of such regulations may result in the imposition of fines or issuances of clean up orders in respect of International Frontier or its assets. Such regulation may be changed to impose higher standards and potentially more costly obligations on International Frontier. There can be no assurance that future environmental costs will not have a material adverse affect on International Frontier. The Company's current exploration acreage is located in the CMV and as such there is additional environmental risk that may not exist in other hydrocarbon basins.

Forward Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "strategy" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this MD&A should not be unduly relied upon. These statements are made only as of the date of this MD&A.

In particular, this MD&A may contain forward-looking statements including, but not limited to, the following:

- oil and natural gas production rates;
- commodity prices for crude oil or natural gas;
- supply and demand for oil and natural gas;
- the estimated quantity of oil and natural gas reserves, including reserve life;
- capital expenditure programs;
- future exploration, development and production costs;
- timing of drilling plans;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to oil and natural gas reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes and tax laws.

With respect to forward-looking statements contained in this MD&A and other documents of public record, the Corporation has made assumptions regarding, among other things:

- future oil and natural gas production levels from IFR's properties and the prices obtained from the sales of such production;
- the level of future capital expenditure required to exploit and develop reserves; and
- the Company's ability to obtain financing on acceptable terms, as required.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of assumptions proving inaccurate and of both known and unknown risks as set forth below:

- general economic, political, market and business conditions;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, capital, acquisitions of reserves, undeveloped lands, drilling equipment and skilled personnel;
- geological, technical, drilling and processing problems;
- incorrect assessments of the value of acquisitions;
- the availability of capital on acceptable terms;
- volatility in market prices for oil and natural gas;
- actions by governmental authorities, including regulatory, environmental and taxation policies; and
- fluctuations in foreign exchange or interest rates and stock market volatility
- ability to raise project finance capital from chartered banks

Other information

Additional information regarding International Frontier Corporation's reserves and other data are available on SEDAR at www.sedar.com