CHINOOK ENERGY INC. TSX:CKE.TO

INTERIM REPORT FOR THE SIX MONTHS ENDED JUNE 30, 2011

Chinook Energy Inc. – Second Quarter 2011 Report

CALGARY, ALBERTA – August 12, 2011 – Chinook Energy Inc. ("Chinook" or the "Company") (TSX: CKE) is pleased to announce its second quarter results.

Chinook's second quarter activity provided important confirmation of commerciality of a significant light oil discovery onshore Tunisia and initial drilling success on an oil-prone resource play in Canada with an encouraging oil and natural gas liquids-rich Doig discovery at Red Creek in northeastern British Columbia.

In Tunisia, Chinook announced encouraging completion results from its three wells on the Sud Remada permit in late May and followed that with 30 day average production numbers of over 1,790 barrels of light oil per day that confirmed the commerciality of the 297 million barrels of Discovered Petroleum-Initially-in-Place (as evaluated by independent reservoir evaluators) light oil discovery from the Ordovician. Water production dropped to less than 3 percent by the end of the period. Chinook pumped five fracture stimulations into seven zones and achieved the key objectives of confirming it could successfully stimulate the portions of the reservoir that were less than one millidarcy permeability (which is an important precursor to testing the application of horizontal well technology to improve the recovery and increase rates) and that it could sustain production at commercial rates from vertical wells. Chinook's expectations were for a combined rate of 1,000 barrels of oil per day and the results exceeded this by a significant margin. Chinook also announced that it had received Tunisian government approval to the granting of the 90,000 acre Bir Ben Tartar Concession, on which the discovery is located, which represents regulatory approval to allow Chinook to commence development of the field. Chinook has currently contracted the rig and equipment required for the next well of a four well development program that will start by the end of August that will support an exit target rate of 3,000 barrels of oil per day gross. Chinook plans to commence a continuous drilling program in early 2012, subject to equipment availability, and forecasts an eventual plateau production rate of 9,000 - 12,000 barrels of oil per day gross. The field will be facility supported and pipeline connected by year end 2012. Based on a Brent crude price of $111.37 per barrel and costs of $26.00 per barrel (field operating and overhead), cash flow from Sud Remada production averaged $85.00 per barrel in June. Chinook's current 54 percent share (86 percent of contractor share under the Production Sharing Contract of 42.5 percent cost oil and 35 percent profit share) of present production of approximately 1,730 barrels of oil per day would generate almost $2.4 million of cash flow per month.

The significance of this development for Chinook cannot be overstated. This discovery has the potential to be a major source of significant reserve additions and stable production growth and Chinook can now confirm that potential will be realized with the development of the 65 square kilometre TT discovery. The Tunisian business segment should generate in excess of $60 million of cash flow in 2012. In addition, Chinook has identified eight other structures on the Sud Remada Block that have been materially de-risked and we will be drilling several of these prospects in 2012. One important attribute of the fiscal regime in Tunisia is that a portion of Chinook's exploration expenditures on its other permits in Tunisia can be cost recovered from the profit portion of revenue generated from a successful discovery like TT, thereby significantly reducing Chinook's risk dollar exposure to an aggressive expansion of exploration programs at Jenein and Hammamet.

The political and social situation in Tunisia is still very fluid and we hope to see signs of increased stability before the end of 2011. Elections originally scheduled for July have been postponed until after Ramadan (October) with over 80 political parties organizing along regional, religious or more traditional political platform lines. The decision making capabilities of the General Directorate for Energy and Entreprise Tunisienne d'Activités Pétrolières have improved, as evidenced by the timely approval of Chinook's Plan of Development for Sud Remada, but there is an increasing concern that this will deteriorate in the absence of political leadership above the ministerial level until new leadership is established by the electoral process. There is a heightened sensitivity to fostering employment, particularly in the southern region where Chinook's operations are located and Chinook's project has the potential to be a very positive influence from a regional benefit and employment perspective. Chinook has been actively engaged in assisting with food and medical aid in response to humanitarian emergencies arising from the Libyan crisis which continue to increase pressure on an already over extended social infrastructure. Trucking and production operations have ramped up substantially since Chinook commenced full time production in early June and to date there have been only minor interruptions in production, and a small number of logistical delays. Chinook's Tunis-based staff have done a masterful job at identifying alternate strategies to keep operations running smoothly in the face of very unpredictable delays and changes in local operating situations.

At Red Creek, in northeast British Columbia, Chinook made an exciting oil and liquids-rich natural gas discovery on one of its domestic resource play concepts that had initial flow rates that are very encouraging on what could prove to be a material project. The 10-stage completion of the 2,880 metre Doig channel discovery well, with a 1,000 metre horizontal section, tested at a final three day average rate of 450 barrels per day and 4.2 millions of cubic feet per day of natural gas with an expected 16 barrels of liquids per million cubic feet of gas recoverable. Facility construction is underway and Chinook expects to commence production by September 1 of this year. Chinook has assembled a strong acreage position on the prospect (20+sections) that will require the drilling of several earning wells prior to the end of the year at an averaged completed well cost of $5 - $6 million.

Drilling activity in Western Canada was minimal during the second quarter owing to spring break up. The planned commencement of an oil development program at Winmore was delayed due to very wet weather in southeast Saskatchewan. Chinook added critical acreage to its land position on two key natural gas resource plays through land sales at Birley in northeast British Columbia and through a farmin where Chinook has committed to drill four wells prior to year end at Knopcik, Alberta. Both of these plays are in areas where Chinook has existing facility capacity and multi-zone conventional targets in addition to material reserve upside to resource style plays in the Montney or Nikanassin.

Second quarter production volumes averaged 14,196 barrels of oil equivalent per day, down 3 percent from the first quarter of 2011 due in large part to material facility turnarounds in June that extended into early July and to a lesser extent, asset sales. Chinook expects third quarter production to average 14,600 barrels of oil equivalent per day with a full quarter's contribution from the Sud Remada discovery. Reported sales volumes for the second quarter were, 13,954 barrels of oil equivalent per day as there was an inventory build attributable to Tunisian production. Oil and liquids represent approximately 33 percent of second quarter production volumes and the average realized barrel of oil equivalent price was up 7 percent from the first quarter to $44.74 per barrel of oil equivalent on higher liquids prices. Chinook expects liquids to represent over 40 percent of its production mix by year end 2011. Netbacks for the second quarter improved slightly to $16.78 per barrel of oil equivalent on the strength of higher revenue, lower royalties, lower General and Administrative expense, and despite a 26 percent increase in operating expenses on a barrel of oil equivalent basis. Tunisian netbacks averaged almost $70 per barrel of oil equivalent including Sud Remada netbacks of $85.00 per barrel of oil equivalent. As volumes increase over the next several quarters, this will become a material contributor to improve per unit metrics. Our disposition program is also contributing, in part, to better per unit results.

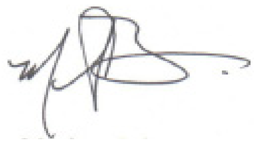
Capital expenditures for the quarter were $16.6 million primarily funded from cash flow ($17.8 million) and asset sale proceeds. Chinook's capital expenditure program for the balance of 2011 is estimated to be $55 - $60 million. For the balance of the year, Chinook expects to drill four-six wells in Tunisia at Bir Ben Tartar and 18 - 20 wells in Canada. The well count is down slightly due to a re-focus of capital to follow up successful exploration results on oil plays which are very capital intensive. The Canadian activity will be focused at Winmore, Gilby, Knopcik and Red Creek.

Chinook has strengthened its balance sheet position and is improving the operational focus of its domestic assets into core areas with the continued rationalization of non-core assets at valuations that are materially accretive to Chinook's trading valuation and not dilutive to corporate plans for future growth. Chinook sold six non-core assets with combined second quarter average production of 135 barrels of oil equivalent per day (37 percent natural gas) for proceeds of $12.3 million, bringing the year-to-date proceeds from dispositions to $30 million. Three additional disposition deals have been negotiated that raise the year-to-date proceeds above $60 million, by the end of the third quarter. The average flowing barrel of oil equivalent metric of the transactions closed and committed year-to-date is above $80,000. Factoring in the asset sales set to close in the third quarter, the borrowing base will be revised to $220 million, down $10 million from the previously available borrowing base. Chinook expects to sell at least $75 million of assets this year and will target the sale of $150 million of non-core assets before the end of 2012. The full year guidance provided in Chinook's first quarter report for average production volumes (14,500 - 14,800 barrels of oil equivalent per day), cash flow ($95 - $100 million) and capital expenditures ($120 - $125 million) are unchanged but a small range has been added to accommodate asset sales. Importantly, Chinook now expects year end debt to be at least $25 million lower than previously forecast, at no more than $150 million.

Chinook also announces the resignation of Mr. Simon Munro from its Board of Directors. Simon has served on Chinook's board since March 21, 2007 and has contributed greatly to the quality of the board and the growth and transition of the corporation. We thank him very much for his valued contributions to Storm Ventures, Silverstone and Chinook over the last 5 years and wish him luck in his future endeavors. Chinook welcomes Townes Pressler, Jr. to the Board of Directors. Mr. Pressler serves as a Managing Director of Lime Rock Partners, a position he has held since joining Lime Rock Partners in 2007. Mr. Pressler brings strong experience in the direct management of junior resource companies, commercial lending, investment banking and corporate governance to the Chinook board and we welcome his input and look forward to working together.

Second quarter operational progress was a welcome and, in the case of Tunisia a long awaited, affirmation of the prospectivity and growth potential in the Chinook asset base. For the rest of the year, we will continue to progress the key projects highlighted to the point that we can support an expanded and much more profitable capital investment program for 2012 than was available to us in 2011. We will aggressively continue with the rationalization of our domestic non-core assets so that our Canadian business is focused on growth and realize this may see us shrink in the short term. Proceeds will be used to bolster our balance sheet and accelerate activity on projects like Bir Ben Tartar and Red Creek. In Tunisia, we will address the logistical and geo political issues to better position us to move to full speed development of our major discovery early in 2012.

We look forward to delivering continued positive confirmation of the growth potential we expect to see over the next few quarters. Thank you for your patience and support.



Matthew J. Brister
President and Chief Executive Officer
Chinook Energy Inc.
August 12, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011

Management's Discussion and Analysis

1. Introduction

The following Management's Discussion and Analysis ("MD&A") is dated August 12, 2011 and should be read in conjunction with the unaudited condensed interim consolidated financial statements and accompanying notes of Chinook Energy Inc. ("Chinook" or the "Company") as at and for the three and six months ended June 30, 2011, Chinook's unaudited condensed interim consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2011, as well as the annual audited consolidated financial statements and notes of Chinook for the year ended December 31, 2010. The consolidated financial position and results of operations include the accounts of the Company's wholly-owned direct and indirect subsidiaries and branch offices. Additional information for the Company, including the Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per share amounts or as otherwise noted.

Chinook is a Calgary-based public oil and natural gas exploration and development company with predominately natural gas and liquids assets in Western Canada and crude oil onshore and offshore in Tunisia, North Africa. Chinook, formerly Storm Ventures International Inc. ("SVI"), is incorporated under the laws of the Province of Alberta, Canada. Chinook's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "CKE". The Company's head office, principal address and registered and records office is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

1.1. 2010 Business Combinations and Asset Acquisitions

On March 11, 2010, the Company indirectly acquired all of the issued and outstanding shares of Talisman Resources (Tunisia) Limited ("TRTL") for USD $23.7 million. TRTL owned a 5% non-operated interest in the Adam Concession and a 10% non-operated interest in the Borj El Khadra Permit, both in Tunisia, North Africa. Subsequent to the acquisition its name was changed to Storm Sahara Limited ("SSL"). The results of SSL are included in the Company's operational and financial results from the date of acquisition.

Two significant Canadian asset acquisitions are accounted for as asset purchases, including the March 1, 2010 and June 30, 2010 acquisitions of crude oil and natural gas assets in West Central Alberta, Canada for combined cost of $220.2 million.

Through a plan of arrangement, on June 29, 2010 (the "Effective Date") SVI acquired all of the issued and outstanding securities of Iteration Energy Ltd. ("Iteration") for net consideration of $366.8 million and upon amalgamation of SVI and Iteration, formed Chinook. Iteration's assets were mainly located in the province of Alberta with the majority of its production from natural gas. The Company's financial information is a continuance of SVI with the results of operations of Iteration included in the accounts from the effective date of the arrangement. The former Iteration exploration and producing assets as acquired on June 29, 2010 combined with the West Central Alberta, Canada asset purchases comprised the Company's entrance into the Western Canadian Sedimentary Basin ("WCSB").

As a result of the 2010 business and asset acquisitions in Western Canada, the Company's comparative periods for the three and six months ended June 30, 2010 do not include entire period's of operational and financial results from these 2010 business and asset acquisitions. As such, the reader is cautioned that comparison between the three and six months ended June 30, 2011 with the same periods in 2010 may not be meaningful.

1.2. 2010 Discontinued Operations

Chinook's indirect wholly-owned subsidiary, Silverstone Energy Limited ("Silverstone"), combined with Bridge Energy Norge AS on March 26, 2010, whereby each company became a subsidiary of a holding company, Bridge Energy ASA ("Bridge Energy"). Chinook's wholly-owned subsidiary Storm Ventures International (BVI) Limited ("SVI (BVI)") formerly owned all of the shares of Silverstone which, at the time, contained Chinook's United Kingdom-North Sea operations. On May 10, 2010, the Company, through SVI (BVI), distributed all of its acquired Bridge Energy shares to its shareholders such that the Company no longer has ownership or holdings in the United Kingdom-North Sea. The Company's former United Kingdom-North Sea operating results have been separately classified and included in net income (loss) from discontinued operations for the comparative periods ended June 30, 2010.

1.3. International Financial Reporting Standards ("IFRS")

On January 1, 2011, the Company adopted IFRS. Prior to January 1, 2010, the Company's financial information was prepared in accordance with previous Canadian generally accepted accounting principles ("Canadian GAAP"). As such, the accounting policies of the Company have been adjusted to comply with IFRS beginning with the Statement of Financial Position as at the date of transition to IFRS on January 1, 2010.

The adoption of IFRS has not had a material impact on the Company's operations, strategic decisions or cash flow. However, the adoption of IFRS had an impact on the Company's Statements of Financial Position and Statements of Net Loss and Comprehensive Income (Loss). Under IFRS, previously reported Canadian GAAP net losses for the three and six months ended June 30, 2010 decreased by $8.9 million and $9.3 million, respectively, as shown in the following reconciliation:

($ thousands)	Three months ended June 30, 2010	Six months ended June 30, 2010
Canadian GAAP net loss	$ (14,570)	$ (26,473)
IFRS net income (loss) adjustments from continuing operations		
Gain on disposition of properties and assets	12,471	12,471
Reduction in depletion expense	1,312	1,599
Reduction in accretion expense (as included in financing expenses)	74	84
Reduction in stock-based compensation	1,288	777
Reduction in foreign exchange gains	(1,555)	(898)
Increase in exploration and evaluation expense	(2,820)	(2,820)
Increase in deferred income tax expense	(1,882)	(1,882)
Total IFRS adjustments	8,888	9,331
IFRS net loss	$ (5,682)	$ (17,142)

A condensed summary of the significant changes, including reconciliations of Canadian GAAP statements of losses and comprehensive losses for the three and six months ended June 30, 2010 and shareholders' equity as at June 30, 2010 to those prepared under IFRS, is presented in Note 14 "International Financial Reporting Standards Adoption" as included in the Company's unaudited condensed interim financial statements for the three and six months ended June 30, 2011. A comprehensive summary of the significant changes, including reconciliations of Canadian GAAP statements of financial position as at January 1, 2010 and December 31, 2010, statement of loss and comprehensive loss for the year ended December 31, 2010, and shareholders' equity as at January 1, 2010 and December 31, 2010 to those prepared under IFRS, is presented in Note 19 "First Adoption of International Financial Reporting Standards" as included in the Company's unaudited condensed interim financial statements for the three months ended March 31, 2011.

The financial information contained in the MD&A and the financial statements for the three and six months ended June 30, 2011, including the comparative information for the 2010 periods, has been prepared in accordance with IFRS, "First-time Adoption of International Financial Reporting Standards" ("IFRS 1") and with International Accounting Standard 34 - "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB") with the exception of non-GAAP measures or financial information reported prior to transition to IFRS on January 1, 2010. Accounting policies compliant with IFRS adopted by the Company are set out in Note 3 to the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2011.

1.4. Forward-Looking Information

Statements throughout this report that are not historical facts may be considered "forward-looking statements". Investors should read the special note regarding forward-looking statements found in section 12.1 of this MD&A.

2. Business Overview

Chinook's continuing operating and reportable segments are as follows:

- **Canada** – includes the Company's WCSB properties and production predominately located in the Peace River Arch Triassic oil discoveries of Red Creek and Knopcik located along the northern border between the Provinces of British Columbia and Alberta and extending down to West Central Alberta through multi zone core areas of Gold Creek, Gilby and Brazeau.
- **Tunisia** – includes eight Tunisian, North African Blocks, including Cosmos located offshore in the Gulf of Hammamet within the Pelagian Basin and Sud Remada, Bir Ben Tartar, Jenein and the contiguous Adam and Borj El Khadra Blocks, all onshore properties located along the Ghadames Basin.
- **Corporate** –includes general and administrative costs and assets held corporately.

Segmented financial information is presented after elimination of intercompany transactions.

3. Financial Summary

3.1. Financial and Operating Results

($ thousands, except per unit amounts)	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Sales Volumes				
Oil sales *(bbl/d)*	**3,152**	1,319	**3,374**	816
Natural gas liquids sales *(bbl/d)*	**1,329**	877	**1,509**	528
Natural gas sales *(mcf/d)*	**56,834**	21,466	**56,381**	14,443
Average daily sales 6:1 *(boe/d)*	**13,954**	5,774	**14,282**	3,751
Sales Prices				
Average oil price *($/bbl)*	**97.71**	72.41	**89.58**	73.22
Average natural gas liquids price *($/bbl)*	**67.03**	48.58	**62.63**	50.87
Average natural gas price *($/mcf)*	**4.00**	4.28	**3.92**	4.45
Average commodity pricing *($/boe)*	**44.74**	39.85	**43.27**	40.24
Production [(3)]				
Oil *(bbl/d)*	**3,394**	1,107	**3,514**	834
Natural gas liquids *(bbl/d)*	**1,329**	877	**1,509**	528
Natural gas *(mcf/d)*	**56,834**	21,466	**56,381**	14,443
Average daily production *(boe/d)*	**14,196**	5,562	**14,421**	3,769
Financial Operations				
Oil, natural gas and natural gas liquids revenue, net of royalties	**47,204**	17,321	**91,569**	22,524
Cash flow (loss) [(1)]	**17,799**	(192)	**38,940**	(1,490)
Per share - basic and diluted [(1)]	**0.08**	-	**0.18**	(0.01)
Net loss from continuing operations	**(1,890)**	(1,354)	**(2,132)**	(3,602)
Per share - basic and diluted	**(0.01)**	(0.01)	**(0.01)**	(0.03)
Capital expenditures [(2)]	**16,569**	260,074	**62,671**	466,073
Net debt [(4)]	**163,138**	183,768	**163,138**	183,768
Total assets	**864,568**	907,971	**864,568**	907,971
Common Shares *(thousands)*				
Weighted average during period				
- basic and diluted	**214,188**	124,124	**214,188**	108,499
Outstanding at period end				
- basic	**214,188**	213,788	**214,188**	213,788
- diluted	**227,815**	220,298	**227,815**	220,298

(1) *Cash flow is a non-GAAP measure and is defined under the non-GAAP measures section of this MD&A.*
(2) *Excludes capitalized costs relating to foreign currency translation incurred during the period and decommissioning obligation.*
(3) *March and June 2010, include acquisitions of Canadian and Tunisian producing assets and assets from the corporate acquisition of Iteration and SSL from the date of acquisition.*
(4) *Net debt is a non-GAAP measure and is calculated as bank debt, less (add) working capital (deficit). Management use this non-GAAP measure to assist them in understanding the Company's liquidity.*

3.2. Financial Highlights

Petroleum and natural gas revenue, net of royalties, of $47.2 million and $91.6 million during the three and six months ended June 30, 2011, respectively, increased $29.9 million and $69.0 million from the $17.3 million and $22.5 million reported during the same periods in 2010. The increase in petroleum and natural gas revenues, net of royalties, during the current periods of 2011, relative to the same periods in 2010, is attributable to higher sales volumes and higher crude oil and natural gas liquids pricing.

Sales volumes of 13,954 boe per day and 14,282 boe per day during the three and six months ended June 30, 2011, respectively, were increases of 142% and 281% relative to the 5,774 boe per day and 3,751 boe per day reported in the same periods during 2010. The increase in the sales volumes during the second quarter of 2011, relative to the same period in 2010, was mostly attributable to the June 2010 corporate acquisition of Iteration and the June 2010 acquisition of certain crude oil and natural gas assets in West Central Alberta, in addition to Chinook's drilling programs during the second half of 2010 and the first half of 2011. The increase in the sales volumes during the six months ended June 30, 2011, relative to the same period in 2010, was for the same reasons as explained for the increase in sales volumes in the second quarter of 2011 relative to the same period in 2010, in addition to the March 2010 corporate acquisition of SSL and the acquisition of predominately natural gas assets in West Central Alberta. For the six months ended June 30, 2011, the Company's commodities sales ratio became more oil weighted as it increased to 24% relative to the 22% reported in the same period in 2010, which further increased revenue given the relatively higher heating value of crude oil pricing relative to natural gas.

The Company's average realized commodity prices of $44.74 per boe and $43.27 per boe during the three and six months ended June 30, 2011, respectively, reflect increases of 12% and 8% relative to the $39.85 per boe and $40.24 per boe realized during the same periods in 2010, primarily as a result of improvements in crude oil and natural gas liquids benchmark pricing. In addition, the average commodity price increased for the six months ended June 30, 2011, as the Company's commodities sales ratio became more oil weighted in comparison to the same period in 2010.

As compared to the petroleum and natural gas revenue, net of royalties during the first quarter of 2011, petroleum and natural gas revenue, net of royalties increased 6% from $44.4 million to $47.2 million in the second quarter of 2011. The increase in petroleum and natural gas revenue, net of royalties, during the second quarter of 2011 relative to the previous quarter was attributable to higher natural gas sales volumes and improved commodity pricing. Natural gas sales volumes during the second quarter of 2011 averaged 56,834 mcf per day, a slight increase from the average of 55,922 mcf per day in the previous period. Commodity pricing improved during the second quarter of 2011 relative to the previous quarter, especially average crude oil and natural gas liquids realized price increases of 19% and 13%, respectively.

Cash flow of $17.8 million and $38.9 million for the three and six months ended June 30, 2011, respectively, increased relative to the cash flow losses of $0.2 million and $1.5 million reported in the same periods during 2010. The increase in cash flows during the three and six months ended June 30, 2011 relative to the same periods in 2010 was primarily attributable to increased commodity sales volumes, higher crude oil and natural gas liquids pricing, and lower general and administration and current tax expenses. Cash flow per share of $0.08 per share and $0.18 per share both on a basic and diluted share basis for the three and six months ended June 30, 2011, respectively, increased from losses per share of approximately $0.01 on a basic and diluted share basis during the same periods in 2010. The increase in cash flow per share for the three and six months ended June 30, 2011 was for the same reasons as already noted herein for the increase in cash flow during the current reporting periods relative to the same periods in 2010 offset by increases in the weighted average of basic and diluted shares resulting from the Company issuing shares in the first half of 2010 to partially finance its corporate acquisition of Iteration and the acquisitions of certain crude oil and natural gas assets.

As compared to cash flow during the first quarter of 2011, cash flow decreased from $21.1 million to $17.8 million in the second quarter of 2011. The decrease in cash flows during the second quarter of 2011 relative to the previous quarter was mostly attributable to lower crude oil sales volumes and higher than normal production and operating expenses resulting from certain well shut-ins to allow for well maintenance and third party facility turnarounds where a portion of the Company's production is processed.

The net loss of $1.9 million for the three months ended June 30, 2011, increased relative to the net loss from continuing operations of $1.4 million during the same quarter in 2010 whereas the net loss of $2.1 million for the six months ended June 30, 2011, decreased relative to the net loss from continuing operations of $3.6 million in the same period in 2010. The decrease in earnings during the second quarter of 2011, relative to the same quarter in 2010, was attributable to certain increased expenses, such as production and operating, primarily resulting from the Company's higher sales volumes, DD&A and deferred income taxes, both non-cash charges, and a lower reported gain on the disposition of properties. The increase in earnings during the six months ended June 30, 2011, relative to the same period in 2010, is primarily due to increased commodity sales volumes, higher crude oil and natural gas liquids pricing, lower expenses related to general and administration and unrealized foreign exchange losses partially offset by increased expenses related to production and operating, DD&A as attributable to higher commodity sales volumes, increased income taxes and financing expenses combined with lower derivative transaction gains.

As compared to the net loss of $0.2 million during the first quarter in 2011, the net loss has increased to $1.9 million in the second quarter of 2011. The increase in the net loss during the second quarter of 2011, relative to the previous quarter, was mostly attributable to certain increased expenses, such as production and operating, and DD&A and deferred income taxes, both non-cash charges, in addition to the Company reporting lower derivative transaction gains. In the second quarter of 2011, relative to the previous quarter, the increase in the net loss was partially offset by higher revenues, net of royalties as mostly attributable to increased natural gas sales volumes and realized commodity pricing and decreased expenses such as general and administration and exploration and evaluation, both cash charges.

3.3. Operational Performance

Production volumes of 14,196 boe per day and 14,421 boe per day during the three and six months ended June 30, 2011, respectively, were increases of 155% and 283% relative to the 5,562 boe per day and 3,769 boe per day reported in the same periods during 2010. In addition to the 2010 corporate acquisitions and asset acquisitions of certain crude oil and natural gas properties in West Central Alberta, the production increases in the current periods, relative to the same periods in 2010, also reflect the June 2011 initial production from the Company's Ordovician oil discovery located on its Bir Ben Tartar Concession. Initial production from this field for June 2011 averaged 1,797 barrels of crude oil per day with a relatively low water cut and 2,500 mcf per day of associated solution gas.

The difference between the Company's production and sales volumes arises from the operations in Tunisia where crude oil is stored in tanks until vessels are contracted for shipment at which time the Company reports revenue. The Company recognizes this portion of its production as crude oil inventory.

Capital expenditures of $16.6 million and $62.7 million for the three and six months ended June 30, 2011, respectively, decreased relative to the capital expenditures of $260.1 million and $466.1 million during the same periods in 2010. Capital expenditures during the current reporting periods has represented organic growth primarily focused on Tunisian and Canadian drilling activities and improvements in the Canadian processing facilities whereas the capital activity during the same periods in 2010 mostly represented the Company's entrance into acquiring exploration and producing properties and assets in Western Canada and to a lesser extent, in Tunisia, North Africa.

3.4. Operational Highlights

For the three months ended June 30, 2011, the Company focused on the following projects, and has set the foundation for additional projects for the remainder of the year to achieve its strategic objectives:

Canada

Peace River Arch District – Chinook drilled and completed the Red Creek 15-1-86-22W6 Doig horizontal well. After a 10-stage propane fracture stimulation the well averaged 450 barrels of oil per day and 4.2 mmcf per day of natural gas. The NGL recovery is anticipated at 16 bbl per mmcf and hydrogen sulfide content of the natural gas is estimated at 10%. Chinook has a 74.55% working interest and operates the well. Key facility equipment was ordered during the second quarter of 2011 and construction of the facility is now underway. Production is estimated to commence prior to September 2011. The Company intends to drill up to two additional wells in 2011, one of which will be a vertical well in which core can be gathered.

Chinook also acquired more than 8,800 hectares of prospective Montney rights in the Birley area of British Columbia. The lands are also prospective for Triassic and Mannville targets. Chinook currently produces approximately 170 boe per day (net) from the area through existing owned and operated infrastructure. Initial plans to evaluate the Montney resource this winter are currently being developed.

Plains District – The second quarter of 2011 was hampered by extreme wet conditions throughout the province affecting the ability to move equipment and truck production. Chinook's Winmore, Saskatchewan and Manyberries, Alberta properties were no exceptions. At Winmore two wells were spud at the end of the first quarter of 2011, however due to the onset of warm weather and rain, operations were suspended after successfully setting surface casing. Drilling operations will be completed in the third quarter of 2011. Prior to break-up Chinook completed the Winmore 4-17-2-30W2M well which commenced production early in the third quarter of 2011 at a rate of 75 barrels of oil per day at 30% water cut. Chinook plans to drill an additional five wells in the field in 2011. Plans are also underway for installation of a central facility in 2012.

West Central District – During the second quarter of 2011, the Company participated in a Cardium horizontal well in the Rosevear area by farming out for a 24% carried working interest through drilling and completion. The well is on production at a gross rate of approximately 100 barrels of oil per day. The Company also conducted two recompletion operations during the second quarter of 2011, one in Gilby and one in Brazeau. The 37.5% working interest well at Gilby was recompleted in the Glauconite formation resulting in a 30 barrels of oil per day well. At Brazeau, the Glauconite formation was recompleted in the 100% working interest well resulting in an initial production rate of more than 125 boe per day. The well has subsequently stabilized at a rate of 60 boe per day. Further operations will be conducted in an additional formation to evaluate horizontal development potential.

Grande Prairie District – The Company conducted three completion operations in the Knopcik and Hythe areas of Grande Prairie during the second quarter of 2011. Two Nikanassin development wells successfully penetrated the producing zone but also resulted in the discovery of a deeper Charlie Lake natural gas zone and a Nikanassin sand not previously encountered. The Charlie Lake zone tested more than 3 mmcf per day and commenced production at a restricted rate of 3.5 mmcf per day with approximately 40 bbl per mmcf of condensate and natural gas liquids. Operations on the Nikanassin zones were suspended due to break-up and will continue in the third quarter of 2011. The Company continues to evaluate its large Nikanassin resource in the general Grande Prairie area and intends to drill a minimum of four additional wells targeting this and other zones through the remainder of 2011. A third well completed in the Braeburn formation tested at an encouraging rate over a short time interval after an oil based frac. The Company anticipates assignment of a maximum rate limitation of approximately 100 barrels of oil per day after completing its new oil well production period, however the Company has also submitted application for good production practice which if approved will not restrict rate. Chinook holds a 74.55% working interest in this well.

Tunisia

The following is a summary of the significant corporate events in Chinook's Tunisian business segment over the second quarter of 2011:

Bir Ben Tartar Concession – A completion program consisting of fracture stimulation of six intervals in three wells TT2, TT3 and TT4 was completed in the second quarter of 2011. The results of the program exceeded expectations with the 30 day average rate of 1,797 barrels of oil per day and 2.5 mmcf per day of associated gas. All three wells are currently producing with the crude being trucked to the offshore loading terminal at La Skhira. Two drilling rigs have already been contracted in order to accelerate Concession development.

Sud Remada Permit – On-going planning for the 2012 exploration program.

Jenein – The interpretation and evaluation of workover options for the JC#1 commitment well are ongoing. A comparison of the Acacus target interval with the same interval in productive wells to the north and the south warrant further investigation. The potential options to access the Acacus target interval on recompletion of this well include a side track off the existing wellbore or the lower cost solvent treatment to remove the mud damage. The technical evaluation of these two options is on-going.

Hammamet – A seismic vessel has been contracted to shoot a 300 square kilometre seismic program starting in August 2011. Approximately 100 square kilometres will be shot over a northern extension of the Tazerka field and merged with the existing 3D seismic data base. The remaining 200 square kilometres will be shot over the Kasserine prospect further to the south on the Block which has potential in the Birsa and Abiod formations. The 3D program is anticipated to fulfill the commitment for a two year extension of the permit.

Adam – Exit production was 535 bbl per day from this Concession, which is in-line with the Company's forecast.

Borj El Khadra – The Bochra-1 well was rig released on May 3, 2011, as a discovery. The prospective formations are Ordovician gas/condensate and light oil in the Acacus and Tannezuft formations. The well has been completed and ENI (the operator) is in the process of applying for approval of a long-term test.

Yasmin – A Plan of Development was submitted to the Tunisian authorities on June 20, 2011.

Cosmos – Preliminary engineering is continuing in preparation of detailed engineering and design work which is planned for later in 2011.

4. Results of Operations

4.1. Operations

Production

Three months ended June 30	2011				2010			
	Oil *(bbl/d)*	**Natural Gas Liquids** *(bbl/d)*	**Gas** *(mcf/d)*	**Total** *(boe/d)*	Oil *(bbl/d)*	Natural Gas Liquids *(bbl/d)*	Gas *(mcf/d)*	Total *(boe/d)*
Canada	**2,674**	**1,329**	**56,099**	**13,353**	567	877	20,710	4,896
Tunisia	**720**	**-**	**735**	**843**	540	-	756	666
Total	**3,394**	**1,329**	**56,834**	**14,196**	1,107	877	21,466	5,562

Six months ended June 30	2011				2010			
	Oil *(bbl/d)*	**Natural Gas Liquids** *(bbl/d)*	**Gas** *(mcf/d)*	**Total** *(boe/d)*	Oil *(bbl/d)*	Natural Gas Liquids *(bbl/d)*	Gas *(mcf/d)*	Total *(boe/d)*
Canada	**2,910**	**1,509**	**55,574**	**13,683**	436	528	13,962	3,291
Tunisia	**604**	**-**	**807**	**738**	398	-	481	478
Total	**3,514**	**1,509**	**56,381**	**14,421**	834	528	14,443	3,769

Canadian Production

The Canadian operating segment's production and sales volumes for the three and six months ended June 30, 2011, increased to 13,353 boe per day and 13,683 boe per day, respectively, increases of 173% and 316% from the volumes achieved in the same periods in 2010. The Canadian production and sales volume increases during both current reporting periods, as compared to the same periods in 2010, is attributable to the Company's corporate acquisition of Iteration, asset acquisitions in June 2010 and drilling activity that Chinook commenced subsequent to its formation. A further reason for the increased Canadian segment's production and sales volumes for the six months ended June 30, 2011, as compared to the same period in 2010, was the asset acquisition in March 2010 of Western Canadian producing properties. For the three and six months ended June 30, 2011, as compared to the same period in 2010, Chinook's Canadian operating segment's drilling activity has focused on improving its commodities volume ratio in favor of crude oil to approximately 20% in both current periods from approximately 12% in both comparative periods given the relatively higher energy equivalency price of crude oil relative to natural gas.

The Canadian operating segment's production and sales volumes during the second quarter of 2011 decreased 5% relative to the 14,014 boe per day realized during the first quarter of 2011. This decrease in production and sales volumes during the second quarter of 2011, relative to the prior quarter, was mostly attributable to the temporary shut-in of certain wells resulting from third party facility turnarounds where a portion of the Company's production is processed and to a lesser extent, the rationalization of certain non-core properties.

Tunisian Production

The Tunisian operating segment's production volumes for the three and six months ended June 30, 2011, increased to 843 boe per day and 738 boe per day, respectively, increases of 27% and 54% from the volumes achieved in the same periods in 2010. The Tunisian production volume increases during both current reporting periods is attributable to the Company's increased production, on both its Bir Ben Tartar Concession and Sud Remada permit, located in Southern Tunisia, resulting from the Company's drilling program during 2010 and 2011. In June 2011, the Company commenced an initial production test of three appraisal wells on its Ordovician oil discovery located on its Bir Ben Tartar Concession. Initial production from this field for June 2011 averaged 1,797 barrels of crude oil per day. The Company's Tunisian operating segment's production further increased for the six months ended June 30, 2011, relative to the same period in 2010, as a result of the March 2010 corporate acquisition of SSL, which increased the Company's working interest to 5% in the producing Adam Concession in addition to the March 2010 additional working interest acquisition in its Sud Remada permit resulting in the holding of an 86% interest.

The Tunisian operating segment's production volumes during the second quarter of 2011 increased 17% relative to the 633 boe per day realized during the first quarter of 2011, primarily as a result of the June 2011 production from the three appraisal wells on the Company's Ordovician oil discovery.

Of the Tunisian operating segment's production for the three and six months, all but a net change of approximately 20,000 boe was sold.

Petroleum and Natural Gas Revenue

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Oil sales	**$ 28,024**	$ 8,694	**$ 54,712**	$ 10,813
Per oil sales *($/bbl)*	**$ 97.71**	$ 72.41	**$ 89.58**	$ 73.22
Natural gas liquids sales	**$ 8,105**	$ 3,878	**$ 17,109**	$ 4,860
Per natural gas liquids sales *($/bbl)*	**$ 67.03**	$ 48.58	**$ 62.63**	$ 50.87
Natural gas sales	**$ 20,683**	$ 8,370	**$ 40,039**	$ 11,644
Per natural gas sales *($/mcf)*	**$ 4.00**	$ 4.28	**$ 3.92**	$ 4.45
Petroleum and natural gas revenue	**$ 56,811**	$ 20,942	**$ 111,860**	$ 27,317
Per petroleum and natural gas revenue *($/boe)*	**$ 44.74**	$ 39.85	**$ 43.27**	$ 40.24

Petroleum and natural gas revenue of $56.8 million and $111.9 million during the three and six months ended June 30, 2011, respectively, increased $35.9 million and $84.5 million from the $20.9 million and $27.3 million reported during the same periods in 2010. The increase in petroleum and natural gas revenues during the current periods of 2011, relative to the same periods in 2010, is attributable to higher sales volumes and higher crude oil and natural gas liquids pricing. The reader is referred to section 3.2 for the explanation of the increase in commodity sales volumes for the Company during the three and six months ended June 30, 2011 relative to the same periods in 2010.

Six months ended June 30, 2011	Benchmark Prices	Average Realized Prices
Oil		
Edmonton par *($/bbl)*	$ 95.57	**$ 86.76**
Brent *($USD/bbl)*	$ 111.16	**$ 104.64**
Natural gas liquids		
Mont Bellevue, KS *($USD/bbl)*	$ 75.39	**$ 61.10**
Natural gas		
AECO *($/mcf)*	$ 3.82	**$ 3.78**

The Company's average realized commodity prices of $44.74 per boe and $43.27 per boe during the three and six months ended June 30, 2011, respectively, increased 14% and 8% relative to the $39.85 per boe and $40.24 per boe realized during the same periods in 2010. The improved average realized price in the current periods of 2011, relative to the same periods in 2010, primarily resulted from improvements in crude oil and natural gas liquids benchmark pricing. The Company's Canadian crude oil production is sold at prices based on the Edmonton par benchmark postings and the Tunisian crude oil production is sold at the three day average price for Brent oil quotations upon being loaded onto a shipping tanker. The Company's Tunisian crude oil, which has a low relative density, has historically sold with a minimal price differential relative to the Brent benchmark. The Edmonton par and Brent benchmarks averaged $95.57 per barrel and USD $111.16 per barrel, respectively, for the six months ended June 30, 2011, both improvements relative to the same period in 2010. Partially offsetting the favorable Brent benchmark was the strengthening of the Canadian dollar, relative to the US dollar, which decreased the Company's realized Tunisian crude oil pricing and revenue. Natural gas liquids are sold at prices historically benchmarked on the monthly spot postings of Mont Bellevue, KS, which improved to $75.39 per barrel for the six months ended June 30, 2011, relative to same period in 2010. The Company's Canadian natural gas liquids has historically had a higher ratio of ethane resulting in a price differential relative to the Mont Bellevue, KS, benchmark. Although the Company's realized natural gas price increased to $4.00 per mcf for the second quarter of 2011, relative to the $3.85 per mcf realized in the prior quarter of 2011 primarily as a result of a higher average AECO benchmark price, realized natural gas prices for the three and six months ended June 30, 2011, decreased relative to the same periods in 2010.

To mitigate commodity price risk, Chinook's management, upon approval of the Board of Directors, has entered into financial derivative contracts which assists the Company in better managing its future cash flows as it knows within a certain commodities price range what it will receive on a portion of its petroleum and natural gas sales volumes. Refer to section 5.6 "Commodity Price Risk Management Contracts" for a further discussion on the Company's financial derivative contracts.

Royalties

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Royalties	**$ 9,607**	$ 3,621	**$ 20,291**	$ 4,793
Per sales *($/boe)*	**$ 7.57**	$ 6.89	**$ 7.85**	$ 7.06
Percent of revenue *(%)*	**17**	17	**18**	18

Primarily as a result of increased sales volumes in the current reporting periods, royalties of $9.6 million and $20.3 million during the three and six months ended June 30, 2011, respectively, increased from the $3.6 million and $4.8 million reported during the same periods in 2010. Royalties per boe, respectively increased to $7.57 per boe and $7.85 per boe for the three and six months ended June 30, 2011, from $6.89 per boe and $7.06 per boe in the same periods in 2010, primarily as a result of increased realized crude oil and natural gas liquids pricing.

There are no royalties incurred on the Bir Ben Tartar Concession as the operations are governed by a production sharing contract with ETAP, the Tunisian national oil company. Under this contract, the Company receives approximately 62% of the production with ETAP receiving the remainder of the production in-kind in-lieu of royalties and taxes paid on behalf of the Company. The recent increase in the Bir Ben Tartar Concession production resulting from the Company's Ordovician oil discovery, has yet to have a significant impact on the lowering of the royalty rate as a percentage of revenue or per boe.

Within the Adam concession in Tunisia, there is a royalty paid on crude oil and natural gas production which is based on a sliding scale calculation with royalty rates of between 2% to 15%. Presently the Company is paying an average royalty rate of 9% for natural gas and 7% for crude oil.

Within the Canadian operations, the Company is subject to Crown royalties, payable to the provincial governments and freehold and gross overriding royalties payable to individuals and corporations that own the mineral rights on which production is obtained.

Production and Operating Expense

($ thousands, except per unit amounts)	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Production and operating expense	**$ 24,326**	$ 7,790	**$ 44,272**	$ 9,669
Per sales *($/boe)*	**$ 19.16**	$ 14.82	**$ 17.13**	$ 14.24

Primarily as a result of increased sales volumes, scheduled Canadian facility turnaround costs and recompletions of certain WCSB wells, production and operating expenses increased to $24.3 million and $44.3 million for the three and six months ended June 30, 2011, respectively, from $7.8 million and $9.7 million for the same periods in 2010. On a boe basis, production and operating expenses increased to $19.16 per boe and $17.13 per boe during the three and six months ended June 30, 2011, respectively, from $14.82 per boe and $14.24 per boe in the same periods in 2010. The increase in production and operating expenses on a boe basis is mostly attributable to scheduled Canadian facility turnarounds and recompletions of certain WCSB wells which increased production and operating expenses in the current reporting periods combined with lower sales volumes than what could have been achieved due to certain WCSB wells that are either tied into such facilities being shut-in during the facility turnarounds or shut-in during the recompletions. The increases in Canadian production and operating expenses on a boe basis, offset the decreases in Tunisian production and operating expenses per boe to $14.10 per boe and $13.25 per boe for the three and six months ended June 30, 2011, respectively, from $24.87 per boe and $20.53 per boe in the same periods in 2010.

General and Administrative Expense ("G&A")

($ thousands, except per unit amounts)	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Stock-based compensation	**$ 1,470**	$ 2,025	**$ 2,720**	$ 3,535
Rent and general office costs	**1,473**	607	**3,425**	1,109
Staffing, net of recoveries	**(148)**	1,408	**(569)**	2,308
Legal expenses	**267**	887	**640**	1,277
Accounting and audit costs	**222**	15	**577**	284
Corporate expenses	**275**	2,635	**940**	3,225
G&A	**$ 3,559**	$ 7,577	**$ 7,733**	$ 11,738
Per sales *($/boe)*	**$ 2.80**	$ 14.42	**$ 2.99**	$ 17.29
Cash G&A [(1)]	**$ 1,561**	$ 5,552	**$ 4,485**	$ 8,203
Per sales *($/boe)*	**$ 1.23**	$ 10.57	**$ 1.73**	$ 12.08

[(1)] Cash G&A is a non-GAAP measure and is calculated as G&A less stock-based compensation and the amortization of the deferred lease liability. Management use this non-GAAP measure to assist them in understanding the cash cost of G&A expenses.

G&A expenses decreased for the three and six months ended June 30, 2011 to $3.6 million and $7.7 million, respectively, from $7.6 million and $11.7 million during the same periods in 2010. The decrease in G&A expenses in the current reporting periods is attributable to decreases in the expense accounts of stock-based compensation, staffing, legal and corporate. The Company's stock-based compensation decreased during the three and six months ended June 30, 2011 to $1.5 million and $2.7 million, respectively, from $2.0 million and $3.5 million in the same periods of 2010 due to a lower number of option grants in the current reporting periods, lower estimated fair values assigned to such grants principally due to lower share price volatility combined with a May 2010 modification of stock option awards resulting from a reduction in the exercise price of all outstanding options, at that time, by $0.78 per option which increased these options' fair value as charged over their vesting periods. Staffing recoveries for the three and six months ended June 30, 2011 of $0.1 million and $0.6 million, respectively, decreased G&A expenses relative to the staffing costs, net of recoveries of $1.4 million and $2.3 million for the same periods in 2010. Despite increased staffing costs associated with the growth in the Canadian and Tunisian producing assets, the Company is in the process of recovering staffing costs incurred by Iteration prior to amalgamation with SVI in addition to staffing recoveries for managing producing and exploratory assets of a related party. Legal and corporate expenses decreased for the three and six months ended June 30, 2011, relative to the same periods in 2010 as a result of costs associated to the 2010 Iteration and SSL corporate acquisitions, in addition to corporation formation costs. Partially offsetting the decrease in G&A were increases in costs related to rent and general office and accounting and audit resulting from the formation of Chinook in June 2010.

Corporate Netbacks (1)

The following tables outline the corporate netbacks by country and on a consolidated basis:

Three months ended June 30	**2011**			2010		
	Canada (2)	**Tunisia**	**Total**	Canada (2)	Tunisia	Total
Sales volumes						
Oil *(bbls/d)*	**2,674**	**478**	**3,152**	567	752	1,319
Natural gas liquids *(bbls/d)*	**1,329**	**-**	**1,329**	877	-	877
Natural gas *(mcf/d)*	**56,099**	**735**	**56,834**	20,710	756	21,472
Total sales volumes *(boe/d)*	**13,353**	**600**	**13,954**	4,896	878	5,774
Per sales *($/boe)*						
Realized sales price	**$ 42.04**	**$104.90**	**$ 44.74**	$ 33.75	$ 73.86	$ 39.85
Less:						
Royalties	**7.25**	**14.69**	**7.57**	6.67	8.10	6.89
Production expense	**19.32**	**15.59**	**19.16**	14.10	18.86	14.82
Cash G&A (3)	**1.07**	**4.76**	**1.23**	12.76	(1.66)	10.57
Corporate netback (1)	**$ 14.40**	**$ 69.86**	**$ 16.78**	$ 0.22	$ 48.56	$ 7.57

Six months ended June 30	**2011**			2010		
	Canada (2)	**Tunisia**	**Total**	Canada (2)	Tunisia	Total
Sales volumes						
Oil *(bbls/d)*	**2,910**	**465**	**3,374**	436	380	816
Natural gas liquids *(bbls/d)*	**1,509**	**-**	**1,509**	528	-	528
Natural gas *(mcf/d)*	**55,574**	**807**	**56,381**	13,962	481	14,442
Total sales volumes *(boe/d)*	**13,682**	**599**	**14,282**	3,291	460	3,751
Per sales *($/boe)*						
Realized sales price	**$ 40.72**	**$101.55**	**$ 43.27**	$ 35.59	$ 73.51	$ 40.24
Less:						
Royalties	**7.71**	**11.13**	**7.85**	6.90	8.23	7.06
Production expense	**17.27**	**13.82**	**17.13**	13.25	21.35	14.24
Cash G&A (3)	**1.60**	**4.80**	**1.73**	12.51	9.04	12.08
Corporate netback (1)	**$ 14.14**	**$ 71.80**	**$ 16.56**	$ 2.93	$ 34.89	$ 6.86

(1) Corporate netback is a non-GAAP measure and is calculated as a period's sales of petroleum and natural gas, net of royalties less production and operating expenses and cash G&A as divided by the period's sales volumes. Management use this non-GAAP measure to assist them in understanding how much of each boe sold can be directed for financing, investing or operating purposes.
(2) Canada also includes all corporate G&A expenses associated with the head office.
(3) See G&A expense table where this non-GAAP measure is defined.

The Company's corporate netbacks for the three and six months ended June 30, 2011 increased to $16.78 per boe and $16.56 per boe, respectively, from $7.57 per boe and $6.86 per boe in the same periods of 2010. The increase in corporate netbacks on a boe basis in the current reporting periods in 2011, relative to the same periods in 2010, primarily resulted from an increase in the Company's realized weighted average commodity price and decreases, on a boe basis, in cash G&A expenses and Tunisian production and operating expenses. The increased corporate netbacks on a boe basis in the current reporting periods of 2011 was partially offset by increases in the Canadian operating costs per boe due to the second quarter of 2011 facilities turnaround costs and recompletions of certain wells in addition to temporary production declines related to the shut-in of wells tied into such facilities or that were being recompleted.

Risk Management Contracts Gains (Losses)

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Realized gains (losses) on risk management contracts	**$ (1,993)**	$ 766	**$ (1,285)**	$ 1,019
Unrealized gains (losses) on risk management contracts	**2,213**	(850)	**3,148**	2,172
	$ 220	$ (84)	**$ 1,863**	$ 3,191

Risk management contract gains for the three and six months ended June 30, 2011, were $0.2 million and $1.9 million, respectively, as compared to a loss of $0.1 million and a gain of $3.2 million in the same periods in 2010. Risk management contract realized losses for the three and six months ended June 30, 2011 reduced the Company's income and cash flows from operations by $2.0 million and $1.3 million, respectively. The realized loss for the six months ended June 30, 2011, would have equated to crude oil and natural gas prices of $83.84 per barrel and $4.14 per mcf, respectively, as compared to the Company's realized crude oil and natural gas prices of $89.58 per barrel and $3.92 per mcf.

Financing Expenses

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Interest on bank debt	**$ 1,913**	$ 4,191	**$ 3,764**	$ 4,193
Interest earned on bank deposits	**(13)**	-	**(22)**	-
Finance charges and fees	**516**	111	**634**	2,711
Accretion of decommissioning liability	**830**	527	**1,890**	704
Financing expenses	**$ 3,246**	$ 4,829	**$ 6,266**	$ 7,608

Finance expenses for the three and six months ended June 30, 2011, decreased to $3.2 million and $6.3 million, respectively, from $4.8 million and $7.6 million in the same periods of 2010, primarily as a result of a decrease in interest on bank debt partially offset by increased accretion of decommissioning liability charges. For the three and six months ended June 30, 2011, interest on bank debt decreased to $1.9 million and $3.8 million, respectively, from $4.2 million in both periods in 2010, primarily due to commitment and financial advising fees on a $167.8 million bridge credit facility entered in June 2010 to assist the Company in financing the corporate acquisition of Iteration in addition to a higher weighted average draw on the Company's revolving term credit facility during the comparative periods. The bridge credit facility was repaid by the Company in August 2010. The outstanding revolving term credit facility accrues interest at either prime plus a margin or at Banker's Acceptance rates plus a margin, depending on the option selected by the Company. Additionally, finance charges of $0.6 million for the six months ended June 30, 2011, decreased from the $2.7 million reported in the same period of 2010 primarily as a result of the Company expensing in the comparative reporting period the fair value of the share purchase warrants associated partially with securing the bridge credit facility. Increased accretion of decommissioning liability costs of $0.8 million and $1.9 million for the three and six months ended June 30, 2011, respectively, relative to the $0.5 million and $0.7 million in the same periods of 2010 was primarily from accreting the Company's decommissioning liability for the entire current reporting periods as compared to only a portion of the comparative reporting periods resulting from the Company acquiring a majority of its existing decommissioning liability through the 2010 corporate acquisitions of Iteration and SSL and the 2010 acquisitions of Western Canadian properties and assets.

Exploration and Evaluation Expenditures ("E&E")

E&E expenditures for the three months ended June 30, 2011 of $0.3 million decreased from $2.8 million in the same quarter of 2010. E&E expenditures for the six months ended June 30, 2011 and 2010 were $2.8 million and $2.7 million, respectively. E&E expenditures include geological and geophysical costs in addition to license transfer fees, studies over unlicensed lands or formations and prospecting expenses. This expense line is new under IFRS.

Depletion, Depreciation and Amortization ("DD&A")

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Canada	**$ 24,362**	$ 8,144	**$ 47,108**	$ 10,817
Tunisia	**675**	862	**1,445**	963
Corporate	**-**	6	**-**	53
Total	**$ 25,037**	$ 9,012	**$ 48,553**	$ 11,833
Per sales *($/boe)*	**$ 19.72**	$ 17.15	**$ 18.78**	$ 17.43

DD&A expenses for the three and six months ended June 30, 2011, of $25.0 million and $48.6 million, respectively, increased from $9.0 million and $11.8 million during the same periods in 2010. For the second quarter of 2011, the increase in DD&A, relative to the same quarter in 2010, was attributable to the Company reporting a full current quarter's DD&A expense associated to the sales volumes from the June 2010 corporate acquisition of Iteration and an asset acquisition of producing properties in addition to the amortization of the associated exploration and evaluation properties acquired through these deals. In addition to the reasons just provided for the increase in DD&A for the second quarter of 2011 relative to the same quarter in 2010, the increase in DD&A for the six months ended June 30, 2011, relative to the same period in 2010, was also attributable to the Company recognizing a full current period's DD&A expense associated with the March 2010 corporate acquisition of SSL and an asset acquisition of producing properties in addition to the amortization of the acquired exploration and evaluation properties acquired through these deals. The Company has included an additional $128.6 million of future development costs in the cost pools subject to depletion.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2011**	2010	**2011**	2010
Current income tax	**$ 1,099**	$ 1,322	**$ 2,156**	$ 1,322
Deferred income tax (recovery)	**885**	(2,918)	**1,371**	(3,846)
Total	**$ 1,984**	$ (1,596)	**$ 3,527**	$ (2,524)

Current income tax expense for the six months ended June 30, 2011, is primarily payable in Tunisia on the Adam Concession producing assets, and has increased, relative to the same period in 2010, as a result of higher sales volumes. The deferred income tax is a result of lower resource pool balances available for tax on the former Iteration assets relative to their net book value in addition to other items partially offsetting higher resource and other pools associated with the remainder of the Canadian operations relative to their netbook values.

4.2. Net Loss and Comprehensive Income (Loss)

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2011**	2010	**2011**	2010
Net loss - continuing operations	**$ (1,890)**	$ (1,354)	**$ (2,132)**	$ (3,602)
Per share - basic and diluted *($/share)*	**$ (0.01)**	$ (0.01)	**$ (0.01)**	$ (0.03)
Net loss	**$ (1,890)**	$ (5,682)	**$ (2,132)**	$ (17,142)
Per share - basic and diluted *($/share)*	**$ (0.01)**	$ (0.05)	**$ (0.01)**	$ (0.16)
Comprehensive income (loss)	**$ (1,589)**	$ 326	**$ (3,624)**	$ (36,214)
Per share - basic and diluted *($/share)*	**$ (0.01)**	$ -	**$ (0.02)**	$ (0.33)
Weighted average shares outstanding - basic and diluted *(thousands)*	**214,188**	124,124	**214,188**	108,499

A net loss per share of $0.01 per share on a basic and diluted share basis for both the three and six months ended June 30, 2011, was comparable with the nil and loss per share of $0.03 on a basic and diluted share basis for continuing operations during the same periods in 2010, respectively. The comparable net loss per share for the three and six months ended June 30, 2011, as compared to the same periods in 2010, was for the same reasons as already noted herein for the change in net losses partially offset by increases in the weighted average number of basic and diluted shares resulting from the Company issuing shares in the first half of 2010 to partially finance its corporate acquisition of Iteration and the acquisitions of certain crude oil and natural gas assets.

Comprehensive losses of $1.6 million and $3.6 million for the three and six months ended June 30, 2011, respectively, includes the Company's net losses and other comprehensive income (loss), as compared to comprehensive income of $0.3 million and a comprehensive loss of $36.2 million for the same periods in 2010. Other comprehensive income for the three months ended June 30, 2011 and 2010 was $0.3 million and $6.0 million, respectively. The decrease in other comprehensive income during the second quarter of 2011, relative to the same quarter in 2010, is attributable to the US dollar not strengthening to the same degree it previously strengthened relative to the Canadian dollar, resulting in a smaller increase in the Company's reported Tunisian net assets as reported in Canadian dollars. In addition, the decrease is attributable to the distribution of the Company's UK operations in May 2010 to the SVI shareholders, which at that time contributed other comprehensive income from the UK Pound Sterling strengthening relative to the Canadian dollar. Other comprehensive losses for the six months ended June 30, 2011 of $1.5 million is attributable to the Canadian dollar strengthening relative to the US dollar resulting in lower reported Tunisian net assets, as reported in Canadian dollars. Other comprehensive losses for the six months ended June 30, 2010, of $19.1 million was attributable to the Canadian dollar strengthening relative to the UK Pound Sterling resulting in lower reported discontinued UK operation's net assets as distributed to the SVI shareholders in May 2010.

5. Capital Resources, Capital Expenditures and Liquidity

Chinook intends to focus on steady growth in volumes from opportunities in its existing asset base to grow conventional liquids production, test resource play concepts in Canada, and develop the light oil discoveries in Tunisia to first production. The Company anticipates that its current production weighting will shift from 85% conventional from Western Canada to a balance of international production and Canadian resource plays as it moves forward.

The Company anticipates it will continue to fund its future work commitments on oil and natural gas properties from cash flow generated from the Canadian and Tunisian operations and by utilizing, when necessary, the available funds from the credit facility in addition to any proceeds received from the rationalization process of non-core properties.

Cash flow for the three and six months ended June 30, 2011, in addition to opening cash balances, proceeds from the disposition of non-core properties and a modest increase in the draws on the Company's revolving term credit facility, financed the investment in non-cash working capital, capital expenditures and exploration and evaluation costs.

5.1. Cash Flow

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2011**	2010	**2011**	2010
Cash flow (loss) from continuing operations	**$ 17,799**	$ (192)	**$ 38,940**	$ (1,490)
Per share - basic and diluted	**0.08**	-	**0.18**	(0.01)
Per sales *($/boe)*	**$ 14.02**	$ (0.37)	**$ 19.06**	$ (2.19)

Cash flow of $17.8 million and $38.9 million for the three and six months ended June 30, 2011, respectively, increased relative to the cash flow losses of $0.2 million and $1.5 million reported in the same periods during 2010. The increase in cash flow during the three and six months ended June 30, 2011 relative to the same periods in 2010 was primarily attributable to increased commodity sales volumes, higher crude oil and natural gas liquids pricing, and lower general and administration, current taxes, cash financing, legal and corporate expenses. Cash flow per share of $0.08 per share and $0.18 per share both on a basic and diluted share basis for the three and six months ended June 30, 2011, respectively, increased from losses per share of approximately $0.01 on a basic and diluted share basis during the same periods in 2010 due to an increase in cash flows in the current reporting periods, relative to the same periods in 2010, partially offset by an increase in the weighted average number of common shares. For the three and six months ended June 30, 2011, cash flow of $14.02 per boe and $19.06 per boe, respectively, increased relative to the cash losses reported in the same periods of 2010. The increase in cash flow per boe in the current reporting periods, relative to the same periods in 2010, is attributable to higher commodity sales volumes relative to lower cash costs associated to such volumes.

Chinook generally relies on operating cash flows and its credit facilities to fund capital requirements and manage liquidity.

5.2. Revolving Term Credit Facility

($ thousands)	**June 30, 2011**	Dec. 31, 2010
Revolving term credit facility	**$ 171,217**	$ 167,793

On June 27, 2011, the Company's 364 day revolving term credit facility was renewed at $230.0 million (the "Revolving Term Credit Facility"). As a result of a petroleum property sale that closed on June 27, 2011, the Revolving Term Credit Facility was reduced by $5.0 million to $225.0 million. The revolving period ends in June 2012. In the event that the revolving period is not extended prior to this date, all amounts then outstanding under the Revolving Term Credit Facility will be payable by June 27, 2013. The Revolving Term Credit Facility is subject to a semi-annual review and redetermination with the next review and redetermination to be calculated based on mid-year information prior to December 31, 2011. Changes in the availability of the Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming immediately payable. At June 30, 2011, the Company had drawn $171.2 million on the Revolving Term Credit Facility (Dec. 31, 2010 - $167.8 million) resulting in unused credit on this facility of $53.8 million (December 31, 2010 - $62.2 million).

The Company's net debt of $164.2 million as at June 30, 2011, decreased relative to $169.4 million as at December 31, 2010. The decrease in net debt is attributable to increased working capital, as defined as current assets less current liabilities.

The Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future properties and assets of the Company. Interest payable on amounts drawn on the facility vary based on Canadian prime, U.S. Base rate, U.S. LIBOR or Bankers' Acceptance depending on the borrowing option selected by the Company. The effective interest rate on the Company's facility for the three and six months ended June 30, 2011 was 4.3% for both periods (2010 - 1.6% and 1.8%, respectively). The facility contains a covenant whereby the Company's debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio where EBITDA, a non-GAAP measure as defined by the credit facility agreement, cannot be greater than 4:1 as determined on an annual basis for the most current fiscal quarter. At June 30, 2011, the Company was in compliance with the covenant.

5.3. Capital Expenditures

Capital Expenditures

Six months ended June 30, 2011

($ thousands)	Canada	Tunisia	Corporate	**Total**
Land and lease	$ 2,904	$ -	$ -	**$ 2,904**
Seismic and G&G	-	1,317	-	**1,317**
Drilling and completions	28,098	10,711	-	**38,809**
Abandonment	3,501	-	-	**3,501**
Facilities and equipment	10,540	657	-	**11,197**
Field expenditures	45,043	12,685	-	**57,728**
Capitalized G&A	1,026	276	-	**1,302**
Furniture and equipment	-	-	349	**349**
Property acquisitions	3,292	-	-	**3,292**
Total	$ 49,361	$ 12,961	$ 349	**$ 62,671**
Proceeds from dispositions	$ 29,960	$ -	$ -	**$ 29,960**

Canada

For the six months ended June 30, 2011, the Company participated in drilling 16 wells (10.64 net). At the Company's Winmore area, Plains District located in Central Alberta, two wells were spud at the end of the first quarter of 2011, however due to the onset of warm weather and rain, operations were suspended after successfully setting surface casing. Drilling operations will be completed in the third quarter of 2011. Again, at Winmore, the Company completed an oil well in the first half of 2011 which commenced production in the third quarter. Chinook drilled and completed the Red Creek 15-1 well, located on its Peace River Arch District in North West Alberta. After a 10-stage propane fracture stimulation, the well averaged 450 boe per day and 4.2 mmcf per day of natural gas, with anticipated NGL recoveries of 16 bbl per mmcf and low hydrogen sulfide content. The Company's Red Creek facility is currently under construction with production from the Red Creek 15-1 well anticipated to commence in August 2011.

The Company also conducted three completion operations at its Knopcik and Hythe areas of Grand Prairie, located in West-Central Alberta. Two Nikanassin development wells successfully penetrated the producing zone but also resulted in the discovery of a deeper Charlie Lake gas zone and Nikanassin sand not previously encountered. The Charlie Lake zone tested more than 3 mmcf per day and commenced production at a restricted rate of 3.5 mmcf per day with approximately 40 bbl per mmcf of condensate and natural gas liquids. Operations on the Nikanassin zones were suspended due to spring break-up and will continue in the third quarter of 2011. A third well completed in the Braeburn formation produced at rates in excess of 1,000 barrels of oil per day for approximately three hours after recovery of load from a 25 tonne oil based frac.

Chinook also acquired more than 8,800 hectares of prospective Montney rights in the Birley area of British Columbia. The lands are also prospective for Triassic and Mannville targets. Chinook currently produces approximately 170 boe per day (net) from the area through existing owned and operated infrastructure. Initial plans to evaluate the Montney resource this winter are currently being developed.

Tunisia

A completion program consisting of fracture stimulation of six intervals in three wells, TT2, TT3 and TT4, was completed in the second quarter of 2011. The results of the program exceeded expectations with the 30 day average rate of 1,797 boe per day and 2.5 mmcf per day of associated gas. All three wells are currently producing with the crude being trucked to the offshore loading terminal at La Skhira. Two drilling rigs have been contracted to accelerate concession development.

A summary of Chinook's drilling activities for the six months ended June 30, 2011, is as follows:

Wells Drilled

Six months ended June 30, 2011	Canada		Tunisia		**Total**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Exploration						
Oil	4.0	1.65	-	-	**4.0**	**1.65**
Gas	4.0	3.25	1.0	0.1	**5.0**	**3.35**
Dry	-	-	-		**-**	**-**
	8.0	4.90	1.0	0.1	**9.0**	**5.00**
Development						
Oil	5.0	3.03	1.0	0.86	**6.0**	**3.89**
Gas	3.0	2.71	-	-	**3.0**	**2.71**
Dry	-	-	-	-	**-**	**-**
	8.0	5.74	1.0	0.86	**9.0**	**6.6**
Total	16.0	10.64	2.0	0.96	**18.0**	**11.60**

5.4. Rationalization of Non-Core Properties

For the six months ended June 30, 2011, the Company has completed the sale of several non-core properties for net proceeds of $29.6 million eventually directed to partially finance the Company's capital expenditures on its core properties in Canada and Tunisia. The non-core properties include Lake Alma in Saskatchewan and Carson Creek, Brazeau, Lloydminster and Paddle River in Alberta with combined production of approximately 277 boe per day in addition to selling various royalty interests. The net carrying value assigned to the non-core properties was less than the proceeds received upon disposition resulting in gains of $6.3 million and $12.5 million for the three and six months ended June 30, 2011, respectively. The Company initially assigned fair value from the corporate and asset acquisitions in the first half of 2010 on the same basis to its non-core properties as it did to its core properties. Only after Chinook was able to thoroughly review its acquired property portfolio, was it in a position to identify non-core properties and commence with the property rationalization process. Through this sequence of events, the Company has reported gains on sales to date on the majority of its property dispositions.

The Company also sold its Jayar and Jarrow non-core properties in purchase and sale agreements which are anticipated to close in August 2011 and is currently evaluating or waiting on offers for other non-core properties. The recognition of gains or losses on the disposition of a property is a requirement under IFRS.

5.5. Outstanding Share Data

Authorized:

- Unlimited number of common shares
- Unlimited number of first preferred shares
- 1,279,000 share purchase warrants (where each share purchase warrant is exercisable to acquire one common share of the Company at a price of $3.25 per common share on or before June 30, 2013)

Details of share capital, options and warrants outstanding are as follows:

	June 30 2011	Dec. 31 2010
Common shares outstanding	**214,187,681**	214,187,681
Share options	**12,348,433**	12,136,394
Share purchase warrants	**1,279,000**	1,279,000
Fully diluted common shares	**227,815,114**	227,603,075
Weighted average common shares - basic and diluted	**214,187,681**	162,002,937

At August 11, 2011, the Company had 214,187,681 common shares, 12,291,016 options and 1,279,000 share purchase warrants outstanding.

5.6. Commodity Price Risk Management Contracts

Chinook's financial results are influenced by fluctuations in commodity prices. As a means of managing this price volatility, Chinook has entered into commodity price contracts for both crude oil and natural gas. Currently, the Company's commodity price risk management contracts provide price protection on approximately 15% of its estimated annual production for 2011. Unsettled risk management contracts are recorded at their fair value on the date of the financial statements. Changes in the fair value of a risk management contract result from volatility in commodity prices and the remaining volumes through to the contract's term. The changes in fair value between reporting periods are recognized in net income (loss) as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income (loss) when the financial derivative contract can be measured with known realized prices. While risk management contracts may have opportunity costs when realized commodity prices exceed the contracted price, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

At June 30, 2011, the Company had commodity price contracts in place with the following remaining terms:

	Volume	Sell/Call	Buy/Put	Term
Natural gas - contract 1	4,500 *GJ/d*	$5.00/*GJ*	$6.40/*GJ*	June 30, 2011 to December 31, 2011
Natural gas - contract 2	3,800 *GJ/d*	$5.00/*GJ*	$7.70/*GJ*	January 1, 2012 to March 1, 2012
Natural gas - contract 3	2,000 *GJ/d*	$6.00/*GJ*		June 30, 2011 to October 31, 2011
Crude oil - contract 1	1,000 *bbl/d*		$85.80 *USD/bbl*	June 30, 2011 to December 31, 2011
Crude oil - contract 2	500 *bbl/d*		$85.70 *USD/bbl*	June 30, 2011 to December 31, 2011
Crude oil - contract 3	1,000 *bbl/d*		$98.75 *USD/bbl*	January 1, 2012 to December 31, 2012 [(1)]

[(1)] On December 31, 2012, at noon (MST) the counterparty holding the commodity contract has the right, but not the obligation, to extend the commodity contract to December 31, 2013, at the price of $98.75 USD/bbl.

5.7. Off Balance Sheet Arrangements

The Company did not enter into any off balance sheet arrangements during the reporting period.

6. Strategic Plan and Outlook

2011 Guidance

The Company for the full year 2011 is expected to average production levels of 14,500-14,800 boe per day which is forecast to generate cash flow of approximately $100.0 million. The Company expects year-end debt to be approximately $175.0 million and anticipates additional asset sales of approximately $25.0 million over the rest of this year. The Company may consider selling a larger portion of non-core assets which will potentially reduce cash flow and volume estimates with a corresponding reduction in bank debt from the forecast provided.

Chinook's Board of Directors has approved a capital expenditure budget of $120.0 million for 2011. The capital program will be financed by funds from operations, access to available bank credit facilities and sale of non-core assets. In estimating cash flow, the Company has assumed an AECO price of $3.75 per mcf for natural gas and $82.00 per bbl for crude oil.

Western Canada

Chinook's consolidated 2011 capital program will direct approximately 75% of expenditures towards oil projects. The Canadian component of the program will accelerate oil projects at Winmore, Gilby and Valhalla and pursue selective liquids rich gas prospects in areas where the Company has the infrastructure support for lower operating costs or a secondary target prospective for oil production. The Company will also test natural gas resource play concepts within its 540,000 acre undeveloped land base where the long-term impact on its growth plans warrants dedicating capital to deliver answers as soon as possible. Chinook drilled 16 wells in Canada during the first half of 2011 and still plans on drilling a total of 34 to 36 wells in 2011. Chinook is also evaluating the shale potential of its lands on the liquids rich portions of both the Muskwa and Nordegg play fairways that may be tested in 2011. Chinook has heavy oil mineral rights on three bitumen accumulations, two of which are adjacent to third-party operated pilot steam-assisted gravity drainage projects that Chinook will study and use this knowledge to assist in assessing the commercial viability of its acreage.

Tunisia

In Tunisia, Chinook will focus its short-term spending on the continued development of the TT discovery at its Bir Ben Tartar Concession. The recycle rate in Tunisia in 2011 supports expanded commitments of capital. The Field Development Plan and new Bir Ben Tartar Concession were approved by the Tunisian authorities on April 27, 2011. Chinook is planning to drill an additional three to four vertical development wells and to fracture stimulate them before December 31, 2011. Planning has also begun in parallel for the construction of a central production facility, an oil sales line and for gas conservation. An independent resource assessment by InSite Petroleum Consultants Ltd. confirmed Discovered Petroleum-Initially-in-Place ("DPIIP") of 297 mmbbl (refer to section 12.3 "Reader Advisory - Discovered Petroleum-Initially-In-Place"). The results on the Bir Ben Tartar Concession also support on-going exploration on the remainder of the Sud Remada permit.

On the Adam permit, Chinook continues to see oil production curtailed as gas oil ratios increase and work towards the sanctioning of the Southern Tunisia Gas Pipeline project continues. The Southern Tunisia Gas Pipeline is expected to be on stream by early 2014 facilitating increased oil production, conservation and sale of solution gas and commencement of production of non-associated gas from the Acacus and the Ordovician Formations. Chinook plans for one to two development wells at Adam, one exploration well at Borj El Khadra and up to seven addition wells in total for Tunisia in the remainder of 2011.

7. Quarterly Information

Summarized information by quarter for the two years ended June 30, 2011, appears below:

($ thousands, except where noted)	**June 30 2011**	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010 (4)	Mar. 31 2010 (4)	Dec. 31 2009 (5)	Sept. 30 2009 (5)
Petroleum and natural gas revenue, net of royalties	**$ 47,204**	$ 44,366	$ 47,227	$ 44,869	$ 17,321	$ 5,193	$ 3,718	$ 2,659
Cash flow (loss) (1)	**17,799**	21,140	22,575	30,643	(192)	(1,298)	2,856	3,139
Per share								
Basic and diluted *($/share)*	**0.08**	0.10	0.11	0.14	-	(0.01)	0.04	0.04
Net income (loss)	**(1,890)**	(241)	(12,218)	2,496	(1,354)	(2,248)	(16,327)	(2,303)
Per share								
Basic and diluted *($/share)*	**(0.01)**	0.00	(0.06)	0.01	(0.01)	(0.02)	(0.23)	(0.03)
Other comprehensive income (loss)	**301**	(2,034)	(2,388)	(2,685)	6,008	(25,080)	(8,476)	(32,281)
Average daily production *(boe)*	**14,196**	14,646	15,354	16,089	5,562	1,705	1,424	1,173
Capital expenditures (2) (3)	**$ 16,569**	$ 46,894	$ 26,827	$ 32,260	$261,838	$ 205,999	$ 4,990	$ 2,141

(1) Cash flow is a non-GAAP measurement and is defined under the non-GAAP measures section of this MD&A.
(2) Excludes capitalized costs relating to foreign currency translation incurred during the period and decommissioning obligation.
(3) March and June 2010, include acquisitions of Canadian and Tunisian producing assets and assets from the corporate acquisitions of Iteration and SSL.
(4) Before discontinued operations for periods March 2010 - June 2010.
(5) As Chinook's IFRS transition date was January 1, 2010, 2009 comparative information has not been restated to IFRS.

Factors That Have Caused Variations over the Quarters

The factors described below only apply to the quarterly information presented above.

The Company completed the acquisition of Canadian and Tunisian producing assets in March 2010, increasing subsequent quarter's production, revenues and cash flow. Natural gas prices have steadily decreased over the quarterly periods shown above, except during the second quarter of 2011, which has contributed to fluctuations in revenue and cash flow for the Company given its commodity sale mix ratio is weighted towards natural gas. Chinook's capital expenditures throughout all of 2010 and 2011, increased significantly due to the subsequent capital expenditures on the Iteration and SSL acquired properties in addition to the subsequent expenditure on the acquired properties in the WCSB, which were acquired during the first and second quarters of 2010. These acquisitions also contributed to the substantial increase in sales revenue and overall production volumes during the second half of 2010 and into 2011.

Please refer to "Results of Operations" and other sections of this MD&A for detailed discussions on variations during the comparative quarters and to Chinook's previously issued interim and annual MD&A for changes in prior quarters.

8. Risk Factors

Chinook is exposed to certain risks and uncertainties inherent in the oil and natural gas industry which include but are not limited to the following:

- Commodity price fluctuations for both crude oil, natural gas and natural gas liquids which are subject to a myriad of factors, are outside of the Company's control;
- Risks arising from exploration and development activities;
- Production risks associated with the depletion and deliverability of reservoirs and the ability to market production;
- The availability and cost of labor, materials and equipment to efficiently, effectively and safely undertake capital projects;
- Environmental and safety concerns; and
- Availability of incremental reserves in commercial quantities of oil and natural gas, whether sourced from exploration, development or acquisitions.

Chinook operates in Tunisia and its operations are exposed to other risks including:

- Exchange rate between the Canadian and the USD dollar for not only commodity prices but also capital spending and operating expenses;
- Changes to government fiscal, monetary and other financial policies;
- Evolution of changing domestic and international climate and environmental policies;
- Terrorism or militant targeted protests directed at international operations;
- Political risk;
- Price controls and varying forms of fiscal regimes or changes thereto; and
- Requirement for permits and licenses for operations.

Many of these risks and uncertainties and others are discussed in the annual information form of Chinook for the year ended December 31, 2010, available on SEDAR at www.sedar.com. Additional risks and uncertainties that management may be unaware of may become important factors which affect Chinook.

Political Risk

Tunisia has experienced a period of political unrest and civil disobedience of increasing intensity which lead to the resignation of the President of Tunisia in favour of an interim government that intends to lead the country until elections can be held later in 2011. Tunisia is bordered by both Algeria and Libya. Both countries have experienced periods of civil, political and military unrest. As reported in the press, Libya had experienced a period of extreme political and civil unrest which has resulted in United Nations sanctions and military intervention to enforce the imposition of a no fly zone which as the potential to further de-stabilize the region. As at the date of this MD&A, Chinook's Tunis office and Bir Ben Tartar field operations are fully staffed for normal business with a full complement of Canadian and Tunisian personnel. Chinook will continue to closely monitor the situation in Tunisia. Due to the transitional nature of the current government, it is possible that delays in receipt of approvals, either regulatory or operational, may cause delays in program delivery beyond what Chinook has forecast. There have been isolated incidents where sporadic peaceful demonstrations targeting improved labour conditions have disrupted the movement of crews and equipment. Depending on the stage of Chinook's operations, this could potentially have an impact on the cost or completion of Chinook's operations. Chinook has security protocols and policies in place to manage the eventualities it considers possible in the current situation. Chinook assesses the situation on a regular basis in the context of its plans and how those plans may be impacted by the local, national and international situation at that time. Although at present, Chinook is proceeding with its operational plan at Bir Ben Tartar, it is possible that the security situation will deteriorate to the point that Chinook deems it appropriate to suspend operations.

Market Risk

Chinook is exposed to market risks such as:

- The cost and availability of capital, which is dependent upon a number of factors including the general economic and market conditions that are beyond the Company's control;
- Interest rate risk; and
- Credit risk.

All, but not limited to, the above risks may impair Chinook's ability to: conduct profitable operations; realize on its assets; or capitalize on opportunities which might become available to it. The success of the Company's capital programs, as embodied in its productivity and reserve base, could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs on a per unit basis are important criteria in determining Company growth, success and access to new capital sources.

The Company attempts to mitigate its business and operational risk exposures by: maintaining comprehensive insurance coverage on its assets and operations; employing or contracting competent technicians and professionals; instituting and maintaining operational health, safety and environmental standards and procedures; employing a commodity hedging program with the goal of minimizing significant downward commodity price movements; and maintaining a prudent approach to exploration and development activities. Chinook attempts to minimize risks associated with exploration by generating exploration prospects internally, targeting high quality projects and attempting to operate the projects. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint ventures partners, however, Chinook does have the ability to withhold production from joint venture partners in the event of non-payment.

9. New Accounting Pronouncement and Standards

These following amendments and standards are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of these new amendments and standards on its consolidated financial statements.

IFRS 10 - *Consolidated Financial Statements*

IFRS 10 *Consolidated Financial Statements* will replace portions of IAS 27 *Consolidated and Separate Financial Statements* and interpretation SIC-12 *Consolidation – Special Purpose Entities*. The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power, and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted.

IFRS 11 - *Joint Arrangements*

IFRS 11 *Joint Arrangements* will apply to interests in joint arrangements where there is joint control. IFRS 11 would require joint arrangements to be classified as either joint operations or joint ventures. The structure of the joint arrangement would no longer be the most significant factor when classifying the joint arrangement as either a joint operation or a joint venture. In addition, only equity accounting would be permitted to account for joint ventures (previously called jointly controlled entities) as previously accounted by the use of proportionate consolidation. Venturers would transition the accounting for joint ventures from the proportionate consolidation method to the equity method by aggregating the carrying values of the proportionately consolidated assets and liabilities into a single line item.

IFRS 12 - *Disclosure of Involvement with Other Entities*

The IASB has issued IFRS 12 *Disclosure of Involvement with Other Entities*, which includes disclosure requirements about subsidiaries, joint ventures, and associates, as well as unconsolidated structured entities and replaces existing disclosure requirements. This standard is effective for annual periods beginning on or after January 1, 2013. Entities will be permitted to apply any of the disclosure requirements in IFRS 12 before the effective date.

IFRS 13 - *Fair Value Measurement*

IFRS 13 generally converges the IFRS and US GAAP requirements for how to measure fair value and the related disclosures. IFRS 13 establishes a single source of guidance for fair value measurements, when fair value is required or permitted by IFRS. The key features of IFRS 13 include: a single framework for measuring fair value while requiring enhanced disclosures when fair value is applied, fair value would be defined as the ‘exit price’, and concepts of ‘highest and best use’ and ‘valuation premise’ would be relevant only for non-financial assets and liabilities. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted.

10. Accounting Estimates

Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect: (i) the reported amounts of assets and liabilities; (ii) the disclosure of any contingent assets and liabilities at the date of the consolidated financial statements; and (iii) revenues and expenses during the period. Chinook’s management reviews its estimates, including those related to accruals, environmental and decommissioning liabilities, recoverability of assets, income taxes, fair values of derivative assets and liabilities, capital adequacy, and the estimation of reserves on an ongoing basis. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Chinook attempts to mitigate this risk by employing individuals with appropriate skill sets and knowledge to make reasonable estimates, developing internal reporting systems, and comparing past estimates to actual results.

The Company's financial and operating results include critical accounting estimates in the following areas:

Determination of Reserves

The proved plus probable natural gas, NGL and crude oil reserves that are used in determining Chinook's depletion rates, the magnitude of the borrowing base available to the Company and impairment testing are based on management's best estimates and are subject to uncertainty. Through the use of geological, geophysical and engineering data, the reservoirs and deposits of natural gas, NGL and crude oil are examined to determine quantities available for future production, given existing operations, economic conditions and technology. The evaluation of reserves is impacted by current production, development activities and changing economic conditions as reflected in commodity prices. To assist with the reserves evaluation process, the Company employs the services of independent oil and natural gas reservoir engineers.

Depletion and Depreciation

Such estimates use the unit-of-production method based on proved plus probable reserves. Given the variability and estimation used in the determination of reserves, depletion and depreciation estimates can have a significant impact on earnings.

Estimate of Recoverability

If capitalized costs associated with long-lived assets such as the costs associated with the acquisition of, exploration for and development of crude oil and natural gas reserves is determined to be in excess of the value in use, which is largely based on reserves estimates, the excess must be written off and charged to earnings. Assumptions about future prices and costs, reserves and discount rates require judgement about highly uncertain future events.

Estimation of Decommissioning Obligation

The Company records a liability for the fair value of its obligation associated with the decommissioning of its net ownership in wells and facilities in the period in which the obligation arises, normally when the asset is purchased or developed. The carrying amount of exploration and evaluation assets and D&P assets are increased by an amount equivalent to the liability. The decommissioning obligation reflects estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of the costs to be incurred in future periods. The obligation is increased each period to reflect the passage of time, with the accretion charged to earnings as a finance expense. The obligation is also adjusted to reflect changes in the amount and timing of such decommissioning obligations and is reduced by the amount of any costs incurred in the period. The amount of future decommissioning costs and the charge for accretion are subject to uncertainty of estimation.

Income Taxes

The determination of Chinook's income and other tax liability requires interpretation of complex domestic and foreign tax laws and regulations. All tax filings are subject to audit and potential reassessments.

Determination of Value of Financial Instruments

Derivative contracts are recorded at fair value based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices. The actual amounts received or paid to settle may vary significantly from the estimate.

Determination of Stock-Based Compensation

A determination of fair value of stock options at the time of grant requires management to assess the volatility of the Company's share price, potential forfeiture rates, estimated life and risk-free interest rates. Given the Company's short trading history, having only listed on the Toronto Stock Exchange on July 6, 2010, the assessment of volatility is derived from an estimation of Chinook's peers. Any changes in these estimations will impact earnings.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates, including revenues, royalties, production costs and capital expenditures as at a specific reporting date, but for which actual revenues and royalties have not yet been received, and estimates on capital projects that are in progress or recently completed where actual costs have not been received at a specific reporting date.

11. Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in the Company's internal controls over financial reporting were identified during the three months ended June 30, 2011, that has materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

12. Other Information

12.1. Forward-Looking Statements

In the interest of providing Chinook's shareholders with information regarding Chinook, including management's assessment of Chinook's future plans and operations, certain statements in this MD&A are "forward-looking statements". In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this MD&A speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this MD&A contains forward-looking statements relating to: the volumes and estimated value of Chinook's petroleum and natural gas reserves; the expected volume of Chinook's petroleum and natural gas production for the full year 2011; future results from operations; future costs and expenses; future exploration and development activities (including drilling plans) and related capital expenditures; Chinook's liquidity and financial capacity; and funding sources for Chinook's capital program.

These forward-looking statements are based on certain key assumptions regarding, among other things: the ability of Chinook to continue to operate in Tunisia with limited logistical, security and operational issues; Chinook's ability to obtain equipment and services in a timely manner to carry out exploration and development activities; Chinook's ability to obtain equity and debt financing on satisfactory terms; future oil and natural gas prices; future well production rates and reserve volumes; Chinook's ability to add commercially viable and economic production and reserves through exploration and development activities; future capital expenditure levels; the availability and cost of labour and other industry services; and interest and foreign exchange rates. The reader is cautioned that such assumptions, although considered reasonable by Chinook at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: political and security risks associated with Chinook's Tunisian operations; general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; 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; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing risks and other difficulties in exploring for producing petroleum reserves; delays resulting from or inability to obtain required regulatory approvals; ability to access sufficient capital from internal and external sources; and other factors, many of which are beyond the control of Chinook. Many of these risks and uncertainties are discussed in Chinook's annual information form for the year ended December 31, 2010 and other documents that Chinook files with the Canadian Securities Regulatory Authority.

There is no representation by Chinook that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Chinook does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

The Company's presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Chinook bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions.

12.2. Non-GAAP Measures

Throughout this MD&A, the Company has presented non-GAAP measures which included "cash flow", "cash flow per share" and "operating netback". These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Cash flow is calculated from cash flow from continuing operations adjusted changes in non-cash working capital. Cash flow per share is calculated from cash flow as previously defined divided by the weighted average basic shares outstanding during the period. Management believes that cash flow is a key measure to assess the ability of the Company operations to -finance capital expenditures and debt repayments. Cash flow as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to cash flow from operations. The following table shows the reconciliation from cash flow from continuing operating activities to cash flow:

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2011**	2010	**2011**	2010
Cash flow (loss) from operations	**$ (1,060)**	$ 2,724	**$ 7,385**	$ 1,812
Add back (deduct) investment in (reduction of) non-cash working capital from continuing operations	**18,859**	(2,916)	**31,555**	(3,302)
Cash flow (loss)	**$ 17,799**	$ (192)	**$ 38,940**	$ (1,490)

Operating netback is calculated as petroleum, natural gas and other reserves revenue less royalties, production expenses and G&A as adjusted for non-cash items including stock-based compensation and amortization of the deferred lease liability. Operating netback is considered important to management as a measure of the Company's profitability relative to current commodity prices and it provides an analysis tool to benchmark changes in non-cash working capital performance against prior periods on a comparable basis.

12.3. Reader Advisory

Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Discovered Petroleum Initially-In-Place

DPIIP (equivalent to discovered resources) is defined in the Canadian Oil and Gas Evaluation Handbook as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves, and contingent resources; the remainder is unrecoverable. There is no certainty that it will be economically viable or technically feasible to produce any portion of the DPIIP except for those portions already produced or identified as reserves.

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011

Condensed Interim Consolidated Statements of Financial Position

(unaudited)

(in thousands of Canadian dollars)	**June 30, 2011**	December 31, 2010 *(note 14)*
Assets		
Current		
Cash	**$ 1,729**	$ 23,195
Accounts receivable *(note 4)*	**49,681**	40,681
Derivative contracts *(note 5)*	**4,538**	3,516
Prepaids, deposits, inventory and other	**9,857**	7,318
	65,805	74,710
Long-term derivative contracts *(note 5)*	**2,505**	1,764
Development and production assets *(note 7)*	**745,810**	748,371
Exploration and evaluation assets *(note 7)*	**50,448**	52,172
	$ 864,568	$ 877,017
Liabilities and Shareholders' Equity		
Current		
Accounts payable, accrued liabilities and other *(note 6)*	**$ 54,488**	$ 68,923
Derivative contracts *(note 5)*	**2,960**	4,345
Taxes payable	**1,333**	3,061
	58,781	76,329
Long-term debt *(note 8)*	**171,217**	167,793
Decommissioning and other long-term liabilities	**130,893**	129,349
Deferred income taxes	**14,798**	13,763
Shareholders' equity		
Share capital *(note 9 (b))*	**778,070**	778,070
Contributed surplus	**14,313**	11,593
Accumulated deficit	**(299,051)**	(296,919)
Accumulated other comprehensive loss	**(4,453)**	(2,961)
	488,879	489,783
	$ 864,568	$ 877,017

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Net Loss and Comprehensive Income (Loss) *(unaudited)*

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
(in thousands of Canadian dollars, except per share amounts)		*(note 14)*		*(note 14)*
Revenue				
Petroleum, natural gas and other revenue, net of royalties *(note 10)*	**$ 49,994**	$ 18,010	**$ 96,570**	$ 23,474
Expense				
Production and operating	**24,326**	7,790	**44,272**	9,669
General and administrative	**3,559**	7,577	**7,733**	11,738
Exploration and evaluation expenditures	**314**	2,820	**2,721**	2,820
Derivative transaction loss (gain) *(note 5)*	**(220)**	84	**(1,863)**	(3,191)
Financing expenses *(note 11)*	**3,246**	4,829	**6,266**	7,608
Depletion, depreciation and amortization *(note 7)*	**25,037**	9,012	**48,553**	11,833
Gain on disposition of properties	**(6,292)**	(12,471)	**(12,475)**	(12,471)
Foreign exchange loss (gain)	**(70)**	1,319	**(32)**	1,594
	49,900	20,960	**95,175**	29,600
Income (loss) before income taxes and discontinued operations	**94**	(2,950)	**1,395**	(6,126)
Income taxes				
Current income tax	**1,099**	1,322	**2,156**	1,322
Deferred income tax (recovery)	**885**	(2,918)	**1,371**	(3,846)
	1,984	(1,596)	**3,527**	(2,524)
Net loss from continuing operations	**(1,890)**	(1,354)	**(2,132)**	(3,602)
Discontinued operations, net of income taxes	**-**	(4,328)	**-**	(13,540)
Net loss	**(1,890)**	(5,682)	**(2,132)**	(17,142)
Foreign currency translation gains (losses) on foreign operations	**301**	6,008	**(1,492)**	(19,067)
Available for sale assets fair value adjustment	**-**	-	**-**	(5)
Comprehensive income (loss)	**(1,589)**	326	**(3,624)**	(36,214)
Net loss per share, basic and diluted *(note 9 (d))*	**$ (0.01)**	$ (0.05)	**$ (0.01)**	$ (0.16)

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(unaudited)

(in thousands of Canadian dollars)	Common Shares *(thousands)* *(note9(b))*	Share Capital *(note9(b))*	Contributed Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Shareholders' Equity
Balance as at January 1, 2011	214,188	$ 778,070	$ 11,593	$ (296,919)	$ (2,961)	$ 489,783
Stock-based compensation *(note 9 (c))*	-	-	2,720	-	-	2,720
Other comprehensive loss for the period	-	-	-	-	(1,492)	(1,492)
Net loss for the period	-	-	-	(2,132)	-	(2,132)
Balance as at June 30, 2011	**214,188**	**$ 778,070**	**$ 14,313**	**$ (299,051)**	**$ (4,453)**	**$ 488,879**

(in thousands of Canadian dollars)	Common Shares *(thousands)* *(note9(b))*	Share Capital *(note9(b))*	Contributed Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Shareholders' Equity
Balance as at January 1, 2010	75,225	$ 344,703	$ 5,116	$ (23,592)	$ -	$ 326,227
Issued on exercise of options	344	1,997	(1,997)	-	-	-
Common shares issued on private placement	85,847	288,584	-	-	-	288,584
Issued on acquisition of Iteration	52,153	141,857	-	-	-	141,857
Common shares issued to employees and directors	219	768	-	-	-	768
Share issue costs	-	(4)	-	-	-	(4)
Stock-based compensation	-	-	3,535	-	-	3,535
Issuance of warrants	-	-	2,611	-	-	2,611
Net loss for the period	-	-	-	(17,142)	-	(17,142)
Dilution adjustment	-	-	-	(27,985)	-	(27,985)
"Return of equity" on Bridge Energy ASA distribution	-	-	-	(218,479)	21,184	(197,295)
Other comprehensive loss for the period	-	-	-	-	(19,072)	(19,072)
Balance as at June 30, 2010 *(note 14)*	**213,788**	**$ 777,905**	**$ 9,265**	**$ (287,198)**	**$ 2,112**	**$ 502,084**

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(unaudited)

	Six months ended June 30	
(in thousands of Canadian dollars)	**2011**	2010
Operating Activities		
Net loss from continuing operations	**$ (2,132)**	$ (3,602)
Add (deduct):		
Accretion	**1,890**	704
Depletion, depreciation and amortization	**48,553**	11,833
Exploration and evaluation expenditures	**2,721**	2,820
Unrealized derivative gain	**(3,148)**	(2,172)
Gain on disposition of properties	**(12,475)**	(12,471)
Foreign exchange loss (gain)	**(32)**	1,594
Shares issued	**-**	115
Stock-based compensation	**2,720**	3,535
Deferred income tax expense (recovery)	**1,371**	(3,846)
Non-cash charges	**(528)**	-
Change in non-cash working capital *(note 12 (a))*	**(31,555)**	3,302
Cash flow from continuing operating activities	**7,385**	1,812
Cash flow from discontinued operations before changes in non-cash working capital	**-**	3,672
Change in non-cash working capital from discontinued operations	**-**	1,047
Cash flow from discontinued operations	**-**	4,719
Cash flow from operating activities	**7,385**	6,531
Financing Activities		
Issue of share capital	**-**	288,584
Long-term debt issue	**3,424**	178,258
Proceeds from exercise of stock options	**-**	49
Share issue costs	**-**	(5)
Change in non-cash working capital *(note 12 (a))*	**(829)**	(2,400)
Cash flow from financing activities	**2,595**	464,486
Investing Activities		
Capital expenditures *(note 7)*	**(62,671)**	(466,073)
Exploration and evaluation expenditures	**(2,721)**	(2,820)
Cash acquired on acquisitions	**-**	(6,210)
Property dispositions	**29,960**	-
Change in non-cash working capital *(note 12 (a))*	**4,567**	30,370
Investing activities from continuing operations	**(30,865)**	(444,733)
Investing activities from discontinued operations	**-**	(2,128)
Cash flow from investing activities	**(30,865)**	(446,861)
Change in cash and cash equivalents, during the period	**(20,885)**	24,156
Cash and cash equivalents, beginning of period	**23,195**	8,027
Cash and cash equivalents, foreign exchange	**(581)**	(716)
Cash and cash equivalents, end of period	**$ 1,729**	$ 31,467

Other supplementary cash flow information *(note 12 (b))*

See accompanying notes to the condensed interim consolidated financial statements.

1. Reporting Entity

Chinook Energy Inc., formerly Storm Ventures International Inc., was incorporated under the laws of the Province of Alberta, Canada, on August 28, 2003. On June 29, 2010, (effective date of the arrangement) through a plan of arrangement, Storm Ventures International Inc. ("SVI") acquired all of the issued and outstanding securities of Iteration Energy Ltd. ("Iteration") and formed Chinook Energy Inc. These condensed interim consolidated financial statements are a continuation of SVI with the results of Iteration included in the accounts from the effective date of the arrangement.

Chinook Energy Inc.'s common shares are listed on the Toronto Stock Exchange under the symbol CKE. The head office, principal address and registered and records office of Chinook Energy Inc. is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

2. Basis of Presentation

Basis of Consolidation

These condensed interim consolidated financial statements include the accounts of Chinook Energy Inc. and its directly and indirectly wholly-owned subsidiaries and foreign branches (collectively, "Chinook" or the "Company"), after the elimination of intercompany balances and transactions.

Nature of Operations

Chinook's current operations are to explore, develop and produce natural gas, crude oil and natural gas liquids in Canada and Tunisia. Each country in which Chinook conducts business has been treated as an identifiable reporting segment, in addition to the corporate segment.

Statement of Compliance

These condensed interim consolidated financial statements have been prepared by management in accordance with IAS 34 'Interim Financial Reporting' ("IAS 34") using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB").

These condensed interim consolidated financial statements present the Company's initial results of operations and financial position in accordance with IFRS as at and for the three and six months ended June 30, 2011, including 2010 comparative periods. As a result, they have also been prepared in accordance with, "First-time Adoption of International Reporting Standards" ("IFRS 1"). Note 14 of these financial statements provides reconciliations of the effects of transition to IFRS from Canadian GAAP on reported financial performance and shareholders' equity of the Company.

Basis of Preparation

The unaudited condensed interim consolidated financial statements have been prepared following the same accounting policies as disclosed in Note 3 in the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2011 and 2010. These condensed interim unaudited consolidated financial statements for the three and six months ended June 30, 2011, should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2011 and 2010 and the notes thereto. These condensed interim consolidated financial statements for the three and six months ended June 30, 2011, do not include all of the required disclosures for annual consolidated financial statements.

Functional and Presentation Currency

These condensed interim consolidated financial statements are presented in Canadian dollars which is also the Company's Canadian and Corporate segment functional currency. The Tunisian segment's functional currency is the United States dollar.

Approval

These condensed interim consolidated financial statements were approved by the Board of Directors and authorized for issuance on August 12, 2011.

3. New Accounting Pronouncement and Standards

These following amendments and standards are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of these new amendments and standards on its consolidated financial statements.

IFRS 10 - *Consolidated Financial Statements*

IFRS 10 *Consolidated Financial Statements* will replace portions of IAS 27 *Consolidated and Separate Financial Statements* and interpretation SIC-12 *Consolidation – Special Purpose Entities*. The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power, and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted.

IFRS 11 - *Joint Arrangements*

IFRS 11 *Joint Arrangements* will apply to interests in joint arrangements where there is joint control. IFRS 11 would require joint arrangements to be classified as either joint operations or joint ventures. The structure of the joint arrangement would no longer be the most significant factor when classifying the joint arrangement as either a joint operation or a joint venture. In addition, only equity accounting would be permitted to account for joint ventures (previously called jointly controlled entities) as previously accounted by the use of proportionate consolidation. Venturers would transition the accounting for joint ventures from the proportionate consolidation method to the equity method by aggregating the carrying values of the proportionately consolidated assets and liabilities into a single line item.

IFRS 12 - *Disclosure of Involvement with Other Entities*

The IASB has issued IFRS 12 *Disclosure of Involvement with Other Entities*, which includes disclosure requirements about subsidiaries, joint ventures, and associates, as well as unconsolidated structured entities and replaces existing disclosure requirements. This standard is effective for annual periods beginning on or after January 1, 2013. Entities will be permitted to apply any of the disclosure requirements in IFRS 12 before the effective date.

IFRS 13 - *Fair Value Measurement*

IFRS 13 generally converges the IFRS and US GAAP requirements for how to measure fair value and the related disclosures. IFRS 13 establishes a single source of guidance for fair value measurements, when fair value is required or permitted by IFRS. The key features of IFRS 13 include: a single framework for measuring fair value while requiring enhanced disclosures when fair value is applied, fair value would be defined as the ‘exit price’, and concepts of ‘highest and best use’ and ‘valuation premise’ would be relevant only for non-financial assets and liabilities. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted.

Tabular amounts in thousands of Canadian dollars, except as noted

4. Accounts Receivable

The Company's accounts receivable is comprised of:

	June 30, 2011	December 31, 2010
Production revenue receivables	**$ 20,811**	$ 21,327
Joint venture partner receivables	**21,476**	15,566
GST input tax credits	**4,883**	1,846
Cash call balances	**1,692**	1,615
Other receivables	**819**	327
	$ 49,681	$ 40,681

The Company's accounts receivable balance is aged as follows:

	June 30, 2011	December 31, 2010
Not past due	**$ 43,516**	$ 29,679
Past due by more than 90 days, net of allowance	**6,165**	11,002
	$ 49,681	$ 40,681

5. Derivative Contracts

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Realized gain (loss) on risk management contract	**$ (1,993)**	$ 766	**$ (1,285)**	$ 1,019
Unrealized gain (loss) on risk management contracts	**2,213**	(850)	**3,148**	2,172
	$ 220	$ (84)	**$ 1,863**	$ 3,191

At June 30, 2011, the following commodity derivative instruments were outstanding and recorded at estimated fair value:

	Volume	Sell/Call	Buy/Put	Remaining term
Natural gas - contract 1	4,500 *GJ/d*	$5.00/*GJ*	$6.40/*GJ*	June 30, 2011 to December 31, 2011
Natural gas - contract 2	3,800 *GJ/d*	$5.00/*GJ*	$7.70/*GJ*	January 1, 2012 to March 1, 2012
Natural gas - contract 3	2,000 *GJ/d*	$6.00/*GJ*		June 30, 2011 to October 31, 2011
Crude oil - contract 1	1,000 *bbl/d*		$85.80 *USD/bbl*	June 30, 2011 to December 31, 2011
Crude oil - contract 2	500 *bbl/d*		$85.70 *USD/bbl*	June 30, 2011 to December 31, 2011
Crude oil - contract 3	1,000 *bbl/d*		$98.75 *USD/bbl*	January 1, 2012 to December 31, 2012 [(1)]

(1) On December 31, 2012, at noon (MST) the counterparty holding the commodity contract has the right, but not the obligation, to extend the commodity contract to December 31, 2013, at the price of $98.75 USD/bbl.

The fair value of the contracts at June 30, 2011, is estimated at $4.1 million and comprised of an unrealized financial asset of $7.0 million, of which $4.5 million and $2.5 million is classified as a current and long-term asset, respectively, and an unrealized current financial liability of $3.0 million.

The use of such instruments is subject to limits established and approved by the Board of Directors. The Company's policy precludes the use of derivative financial instruments for speculative purposes.

Tabular amounts in thousands of Canadian dollars, except as noted

6. Accounts Payable, Accrued Liabilities and Other

The Company's accounts payable, accrued liabilities and other are comprised of:

	June 30, 2011	December 31, 2010
Trade accounts payable	**$ 10,849**	$ 11,961
Royalties payable	**1,180**	1,983
Joint venture accounts payable	**17,314**	16,912
Accrued liabilities	**24,089**	38,067
Deferred lease costs	**1,056**	-
	$ 54,488	$ 68,923

7. Development and Production and Exploration and Evaluation Assets

	Development and Production Assets	Exploration and Evaluation Assets	Total
Cost of Assets			
Balance as at December 31, 2010	$ 804,122	$ 61,009	$ 865,131
Capital expenditures	59,485	3,186	62,671
Asset retirement costs	1,292	-	1,292
Cost of properties sold	(17,441)	(44)	(17,485)
Foreign exchange adjustment	(2,160)	-	(2,160)
Balance as at June 30, 2011	**$ 845,298**	**$ 64,151**	**$ 909,449**
Accumulated Depletion and Depreciation			
Balance as at December 31, 2010	$ (55,751)	$ (8,837)	$ (64,588)
Provisions	(43,687)	(4,866)	(48,553)
Inventoried depletion	(582)	-	(582)
Foreign exchange adjustment	532	-	532
Balance as at June 30, 2011	**$ (99,488)**	**$ (13,703)**	**$ (113,191)**
Net Book Values			
Balance as at December 31, 2010	$ 748,371	$ 52,172	$ 800,543
Balance as at June 30, 2011	**$ 745,810**	**$ 50,448**	**$ 796,258**

Corporate assets with a net book value of $3.1 million have been included in development and production assets. The Company capitalized $1.3 million (2010 - $0.7 million) of direct G&A costs as related to its exploration and development activity for the six months ended June 30, 2011.

Tabular amounts in thousands of Canadian dollars, except as noted

Future development costs were added to the costs subject to depletion as follows:

	June 30, 2011
Canada	**$ 55,211**
Tunisia	**73,352**
	$ 128,563

8. Debt

On June 27, 2011, the Company's 364 day revolving term credit facility was renewed at $230.0 million (the "Revolving Term Credit Facility"). As a result of a petroleum property sale that closed on June 27, 2011, the Revolving Term Credit Facility was reduced by $5.0 million to $225.0 million. The revolving period ends in June 2012. In the event that the revolving period is not extended prior to this date, all amounts then outstanding under the Revolving Term Credit Facility will be payable by June 27, 2013. The Revolving Term Credit Facility is subject to a semi-annual review and redetermination with the next review and redetermination to be calculated based on mid-year information prior to December 31, 2011. Changes in the availability of the Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming immediately payable. At June 30, 2011, the Company had drawn $171.2 million on the Revolving Term Credit Facility (December 31, 2010 - $167.8 million) resulting in available credit on this facility of $53.8 million (December 31, 2010 - $62.2 million).

The Revolving Term Credit Facility is collateralized by floating charges and security interests over all present and future properties and assets of the Company. Interest payable on amounts drawn on this facility vary based on Canadian prime, U.S. Base rate, U.S. LIBOR or Bankers' Acceptance depending on the borrowing option selected by the Company. The effective interest rate on the Company's facility for the three and six months ended June 30, 2011, was 4.3% for both periods, (2010 - 1.6 and 1.8%, respectively). The facility contains a covenant whereby the Company's debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio where EBITDA, a non-GAAP measure as defined by the credit facility agreement, cannot be greater than 4:1 as determined on an annual basis for the most current fiscal quarter. At June 30, 2011, the Company was in compliance with the covenant.

9. Share Capital

a) Authorized:

An unlimited number of no par value common shares and first preferred shares in addition to 1,279,000 share purchase warrants.

b) Issued and Outstanding:

Common Shares

All common shares are fully paid. The holders of common shares are entitled to share equally in dividends, returns of capital and to vote at shareholders' meetings.

	Number of Common Shares *(thousands)*	Amount
Balance as at December 31, 2010 and June 30, 2011	214,188	$ 778,070

First Preferred Shares

No first preferred shares, whose terms are yet to be determined, have been issued.

Warrants

The Company issued 1,279,000 share purchase warrants ("Warrants") on May 27, 2010, in consideration for financing related to the formation of the Company. As at June 30, 2011 and December 31, 2010, all of the Warrants were outstanding. Each Warrant is exercisable to acquire one common share of the Company at a price of $3.25 per common share on or before June 30, 2013.

Tabular amounts in thousands of Canadian dollars, except as noted

c) Stock-Based Compensation Plan

The Company has a share option plan pursuant to which options to purchase common shares of the Company may be granted to employees, directors, officers, and other service providers of the Company. The maximum number of common shares issuable on exercise of options granted pursuant to the share option plan may not exceed 10% of the issued and outstanding common shares of the Company. The outstanding options of the Company vest over a period of three years and expire five years after the date granted.

A summary of options outstanding is as follows:

	Number of Options *(thousands)*
Balance as at December 31, 2010	12,136
Granted during the period	845
Exercised during the period	-
Forfeited during the period	(633)
Balance as at June 30, 2011	**12,348**

The table below summarizes outstanding stock options and the weighted average exercise prices remaining life in years, the number of exercisable options and their respective weighted average exercise prices and remaining life.

	Outstanding Options			Options Exercisable		
Range of Exercise Prices *($/option)*	Options Outstanding *(thousands)*	Weighted Average Exercise Prices *($/option)*	Weighted Average Remaining Life *(years)*	Options Outstanding *(thousands)*	Weighted Average Exercise Prices *($/option)*	Weighted Average Remaining Life *(years)*
$ 1.80 - $1.85	1,056	$ 1.83	4.5	-	$ -	-
$ 1.86 - $2.20	7,161	2.11	3.9	760	1.97	3.1
$ 2.21 - $2.72	4,131	2.57	3.9	740	2.70	3.7
	12,348	$ 2.24	4.0	1,500	$ 2.33	3.4

Total stock-based compensation, as included in the line item general and administrative expense as reported in the Condensed Interim Consolidated Statements of Net Loss and Comprehensive Income (Loss), for the three and six months ended June 30, 2011, was $1.5 million and $2.7 million, respectively (2010 - $2.0 million and $3.5 million, respectively). The following factors were used in the Black-Scholes pricing model for the determination of the fair value for options granted during the six months ended June 30, 2011 and 2010:

	Six months ended June 30	
	2011	2010
Expected average life *(years)*	**1 to 3**	1 to 5
Risk-free interest rate *(%)*	**2.2 to 2.8**	2.5 to 2.8
Estimated forfeiture rate per annum *(%)*	**0 to 30**	0 to 30
Volatility factor *(%)*	**57.8 to 58.3**	83.1 to 100.5

The weighted average fair value determined for options granted during the three and six months ended June 30, 2011, was $0.49 and $0.52 per option, respectively (2010 - $2.18 and $1.82 per option, respectively).

Tabular amounts in thousands of Canadian dollars, except as noted

d) Per Share Amounts

The per share amounts for the three and six months ended June 30, 2011 and the same periods during 2010, were calculated as per the following table. Diluted income per share assumes the exercise of options and Warrants as if issued at the later of the date of grant or the beginning of the period. This calculation takes into account only the options and Warrants that are considered to be "in-the-money" at June 30, 2011. Based on the Company's share price at June 30, 2011, per the treasury method, there were no additional shares that would have been added to the weighted average diluted shares outstanding for the three and six months ended June 30, 2011 and three and six months ended June 30, 2010.

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Net loss - continuing operations	**$ (1,890)**	$ (1,354)	**$ (2,132)**	$ (3,602)
Per share - basic and diluted *($/share)*	**(0.01)**	(0.01)	**(0.01)**	(0.03)
Net loss	**$ (1,890)**	$ (5,682)	**$ (2,132)**	$ (17,142)
Per share - basic and diluted *($/share)*	**(0.01)**	(0.05)	**(0.01)**	(0.16)
Weighted average shares outstanding - basic and diluted *(thousands)*	**214,188**	124,124	**214,188**	108,499

10. Petroleum, Natural Gas and Other Revenue, Net of Royalties

	Three months ended June 30		Six months ended June 30	
	2011	2010 [(1)]	**2011**	2010 [(1)]
Oil revenue	**$ 28,024**	$ 8,694	**$ 54,712**	$ 10,813
Natural gas and gas liquids revenue	**28,787**	12,248	**57,148**	16,504
Other	**2,790**	689	**5,001**	950
Petroleum, natural gas and other revenue	**59,601**	21,631	**116,861**	28,267
Royalties	**(9,607)**	(3,621)	**(20,291)**	(4,793)
Petroleum, natural gas and other revenue, net of royalties	**$ 49,994**	$ 18,010	**$ 96,570**	$ 23,474

[(1)] *From continuing operations.*

11. Financing Expenses

	Three months ended June 30		Six months ended June 30	
	2011	2010	**2011**	2010
Interest on bank debt	**$ 1,913**	$ 4,191	**$ 3,764**	$ 4,193
Interest earned on bank deposits	**(13)**	-	**(22)**	-
Finance charges and fees	**516**	111	**634**	2,711
Accretion of decommissioning liability	**830**	527	**1,890**	704
Financing expenses	**$ 3,246**	$ 4,829	**$ 6,266**	$ 7,608

Tabular amounts in thousands of Canadian dollars, except as noted

12. Supplemental Cash Flow Information

a) Changes in Non-Cash Working Capital:

	Six months ended June 30	
	2011	2010
Accounts receivable	**$ (8,907)**	$ (32,284)
Prepaids, deposits, inventory and other	**(1,623)**	5,744
Accounts payable, accrued liabilities and other	**(15,559)**	57,559
Taxes payable	**(1,728)**	1,300
Changes in non-cash working capital	**$ (27,817)**	$ 32,319
Relating to:		
Financing activities	**$ (829)**	$ (2,400)
Investing activities	**4,567**	30,370
Operating activities	**(31,555)**	4,349
Changes in non-cash working capital	**$ (27,817)**	$ 32,319

b) Other Supplemental Cash Flow Information:

	Six months ended June 30	
	2011	2010
Cash taxes paid	**$ 4,102**	$ 3,441
Cash interest paid	**$ 3,894**	$ 393

13. Segmented Information

The Company's current operating and reportable segments are as follows:

- **Canada** – includes the Company's Western Canadian Sedimentary Basin properties and production predominately located in the Peace River Arch Triassic oil discoveries of Red Creek and Knopcik located along the northern border between the Provinces of British Columbia and Alberta and extending down to West Central Alberta through multi zone core areas of Gold Creek, Gilby and Brazeau.
- **Tunisia** – includes eight Tunisian, North African Blocks, including Cosmos located offshore in the Gulf of Hammamet within the Pelagian Basin and Sud Remada, Bir Ben Tartar, Jenein and the contiguous Adam and Borj El Khadra Blocks, all onshore properties located along the Ghadames Basin.
- **Corporate** – includes general and administrative costs and assets held corporately.

Segment and Geographic Information

	Canada		Tunisia		Corporate		Consolidated	
Six months ended June 30	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Capital expenditures	**$ 49,362**	$ 442,051	**$ 12,960**	$ 23,736	**$ 349**	$ 286	**$ 62,671**	$ 466,073
Development and production and exploration and evaluation assets	**$ 715,470**	$ 755,434	**$ 77,704**	$ 69,301	**$ 3,084**	$ 713	**$ 796,258**	$ 825,448
Total assets	**$ 778,606**	$ 809,737	**$ 83,214**	$ 90,508	**$ 2,748**	$ 7,726	**$ 864,568**	$ 907,971

Tabular amounts in thousands of Canadian dollars, except as noted

Results by Segment

	Canada		Tunisia		Corporate		Consolidated	
Three months ended June 30	**2011**	2010	**2011**	2010	**2011**	2010 [(1)]	**2011**	2010 [(1)]
Revenue								
Petroleum, natural gas and other revenue, net of royalties	**$ 45,067**	$ 12,751	**$ 4,927**	$ 5,259	**$ -**	$ -	**$ 49,994**	$ 18,010
Expenses								
Production and operating	**23,475**	6,283	**851**	1,507	**-**	-	**24,326**	7,790
General and administrative	**3,264**	7,677	**263**	(491)	**32**	391	**3,559**	7,577
Exploration and evaluation expenditures	**7**	6	**307**	2,814	**-**	-	**314**	2,820
Derivative transactions loss (gain)	**(220)**	84	**-**	-	**-**	-	**(220)**	84
Financing expenses	**3,351**	4,752	**(107)**	63	**2**	14	**3,246**	4,829
Depletion, depreciation and amortization	**24,362**	8,144	**675**	862	**-**	6	**25,037**	9,012
Gain on disposition of properties	**(6,292)**	(12,471)	**-**	-	**-**	-	**(6,292)**	(12,471)
Foreign exchange loss (gain)	**-**	164	**(70)**	1,369	**-**	(214)	**(70)**	1,319
	47,947	14,639	**1,919**	6,124	**34**	197	**49,900**	20,960
Income (loss) before income taxes and discontinued operations	**(2,880)**	(1,888)	**3,008**	(865)	**(34)**	(197)	**94**	(2,950)
Current income tax	**(121)**	-	**1,220**	1,322	**-**	-	**1,099**	1,322
Deferred income tax (recovery)	**403**	(1,587)	**482**	(1,331)	**-**	-	**885**	(2,918)
Discontinued operations, net of income taxes [(1)]	**-**	-	**-**	-	**-**	(4,328)	**-**	(4,328)
Net income (loss)	**$ (3,162)**	$ (301)	**$ 1,306**	$ (856)	**$ (34)**	$ (4,525)	**$ (1,890)**	$ (5,682)

[(1)] *United Kingdom segment was sold in May 2010 and shown as discontinued operations in the Corporate segment during the three months ended June 30, 2010.*

Tabular amounts in thousands of Canadian dollars, except as noted

	Canada		Tunisia		Corporate		Consolidated	
Six months ended June 30	**2011**	2010	**2011**	2010	**2011**	2010 [1]	**2011**	2010 [1]
Revenue								
Petroleum, natural gas and other revenue, net of royalties	**$ 86,765**	$ 18,021	**$ 9,805**	$ 5,453	**$ -**	$ -	**$ 96,570**	$ 23,474
Expenses								
Production and operating	**42,773**	7,892	**1,499**	1,777	**-**	-	**44,272**	9,669
General and administrative	**7,134**	10,986	**520**	393	**79**	359	**7,733**	11,738
Exploration and evaluation expenditures	**2,070**	6	**651**	2,814	**-**	-	**2,721**	2,820
Derivative transactions gain	**(1,863)**	(3,191)	**-**	-	**-**	-	**(1,863)**	(3,191)
Financing expenses	**6,241**	7,517	**22**	83	**3**	8	**6,266**	7,608
Depletion, depreciation and amortization	**47,108**	10,817	**1,445**	963	**-**	53	**48,553**	11,833
Gain on disposition of properties	**(12,475)**	(12,471)	**-**	-	**-**	-	**(12,475)**	(12,471)
Foreign exchange loss (gain)	**8**	164	**(41)**	905	**1**	525	**(32)**	1,594
	90,996	21,720	**4,096**	6,935	**83**	945	**95,175**	29,600
Income (loss) before income taxes and discontinued operations	**(4,231)**	(3,699)	**5,709**	(1,482)	**(83)**	(945)	**1,395**	(6,126)
Current income tax	**(113)**	-	**2,269**	1,322	**-**	-	**2,156**	1,322
Deferred income tax (recovery)	**403**	(2,515)	**968**	(1,331)	**-**	-	**1,371**	(3,846)
Discontinued operations, net of income taxes [1]	**-**	-	**-**	-	**-**	(13,540)	**-**	(13,540)
Net income (loss)	**$ (4,521)**	$ (1,184)	**$ 2,472**	$ (1,473)	**$ (83)**	$ (14,485)	**$ (2,132)**	$(17,142)

[1] *United Kingdom segment was sold in May 2010 and shown as discontinued operations in the Corporate segment during the six months ended June 30, 2010.*

14. International Financial Reporting Standards Adoption

The Company adopted IFRS on January 1, 2011, with a transition date of January 1, 2010, (the "Transition Date"). Prior to adopting IFRS, the Company prepared its interim and annual consolidated financial statements in accordance with Canadian GAAP. While the adoption of IFRS has not changed the Company's cash flows, the adoption has resulted in changes to its reported financial position and results of operations. This note sets out how the transition from Canadian GAAP to IFRS has affected the Company's comprehensive income (loss) for the three and six months ended June 30, 2010 in addition to shareholders' equity as at June 30, 2010.

Please refer to the notes that follow the detailed reconciliations.

Tabular amounts in thousands of Canadian dollars, except as noted

Reconciliation of Total Comprehensive Income from Canadian GAAP to IFRS

Reconciliation of Consolidated Income for the Three Months Ended June 30, 2010:

(unaudited)

		Adjustments						
	GAAP	IAS 16 *(note b)*	IFRS 2 *(note c)*	IAS 37 *(note d)*	IAS 21 *(note e)*	IFRS 6 *(note f)*	Total	IFRS
Revenue								
Petroleum, natural gas and other revenue, net of royalties	$ 18,010	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,010
Expenses								
Production and operating	7,790	-	-	-	-	-	-	7,790
General and administrative	8,865	-	(1,288)	-	-	-	(1,288)	7,577
Exploration and evaluation expenditures	-	-	-	-	-	2,820	2,820	2,820
Derivative transaction loss	84	-	-	-	-	-	-	84
Financing expenses	4,302	-	-	527	-	-	527	4,829
Depletion, depreciation and amortization	10,925	(1,312)	-	(601)	-	-	(1,913)	9,012
Gain on disposition of properties	-	(12,471)	-	-	-	-	(12,471)	(12,471)
Foreign exchange loss (gain)	(236)	-	-	-	1,555	-	1,555	1,319
	31,730	(13,783)	(1,288)	(74)	1,555	2,820	(10,770)	20,960
Income (loss) before income taxes and discontinued operations	(13,720)	13,783	1,288	74	(1,555)	(2,820)	10,770	(2,950)
Income taxes								
Current income tax	1,322	-	-	-	-	-	-	1,322
Deferred income tax expense (recovery) *(note g)*	(4,800)	3,906	-	21	(494)	(1,551)	1,882	(2,918)
Net income (loss) from continuing operations	(10,242)	9,877	1,288	53	(1,061)	(1,269)	8,888	(1,354)
Discontinued operations, net of income taxes	(4,328)	-	-	-	-	-	-	(4,328)
Net income (loss)	$(14,570)	$ 9,877	$ 1,288	$ 53	$(1,061)	$(1,269)	$ 8,888	$ (5,682)
Net income (loss) per share, basic and diluted, continuing operations	$ (0.08)	$ 0.08	$ 0.01	$ -	$ (0.01)	$ (0.01)	$ 0.07	$ (0.01)
Net loss per share, basic and diluted, discontinued operations	$ (0.03)	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.03)
Consolidated statement of comprehensive income (loss)								
Net income (loss)	$ (14,570)	$ 9,877	$ 1,288	$ 53	$(1,061)	$(1,269)	$ 8,888	$ (5,682)
Foreign currency translation gain on foreign operations	1,322	-	-	-	4,686	-	4,686	6,008
Comprehensive income (loss)	$ (13,248)	$ 9,877	$ 1,288	$ 53	$ 3,625	$(1,269)	$13,574	$ 326
Comprehensive income (loss) per share, basic and diluted	$ (0.11)	$ 0.08	$ 0.01	$ -	$ 0.03	$ (0.01)	$ 0.11	$ -

Tabular amounts in thousands of Canadian dollars, except as noted

Reconciliation of Total Comprehensive Income from Canadian GAAP to IFRS

Reconciliation of Consolidated Income for the Six Months Ended June 30, 2010:

(unaudited)

		Adjustments						
	GAAP	IAS 16 *(note b)*	IFRS 2 *(note c)*	IAS 37 *(note d)*	IAS 21 *(note e)*	IFRS 6 *(note f)*	Total	IFRS
Revenue								
Petroleum, natural gas and other revenue, net of royalties	$ 23,474	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,474
Expenses								
Production and operating	9,669	-	-	-	-	-	-	9,669
General and administrative	12,515	-	(777)	-	-	-	(777)	11,738
Exploration and evaluation expenditures	-	-	-	-	-	2,820	2,820	2,820
Derivative transaction gain	(3,191)	-	-	-	-	-	-	(3,191)
Financing expenses	6,904	-	-	704	-	-	704	7,608
Depletion, depreciation and amortization	14,220	(1,599)	-	(788)	-	-	(2,387)	11,833
Gain on disposition of properties	-	(12,471)	-	-	-	-	(12,471)	(12,471)
Foreign exchange loss	696	-	-	-	898	-	898	1,594
	40,813	(14,070)	(777)	(84)	898	2,820	(11,213)	29,600
Income (loss) before income taxes and discontinued operations	(17,339)	14,070	777	84	(898)	(2,820)	11,213	(6,126)
Income taxes								
Current income tax	1,322	-	-	-	-	-	-	1,322
Deferred income tax expense (recovery) *(note g)*	(5,728)	3,906	-	21	(494)	(1,551)	1,882	(3,846)
Net income (loss) from continuing operations	(12,933)	10,164	777	63	(404)	(1,269)	9,331	(3,602)
Discontinued operations, net of income taxes	(13,540)	-	-	-	-	-	-	(13,540)
Net income (loss)	$ (26,473)	$10,164	$ 777	$ 63	$ (404)	$ (1,269)	$ 9,331	$ (17,142)
Net income (loss) per share, basic and diluted, continuing operations	$ (0.12)	$ 0.09	$ 0.01	$ -	$ -	$ (0.01)	$ 0.09	$ (0.03)
Net loss per share, basic and diluted, discontinued operations	$ (0.12)	$ -	$ -	$ -	$ -	$ -	$ -	$ (0.12)
Consolidated statement of comprehensive income (loss)								
Net income (loss)	$ (26,473)	$10,164	$ 777	$ 63	$ (404)	$ (1,269)	$ 9,331	$ (17,142)
Foreign currency translation gains (losses) on foreign operations	(21,179)	-	-	-	2,112	-	2,112	(19,067)
Available for sale assets fair value adjustment	(5)	-	-	-	-	-	-	(5)
Comprehensive income (loss)	$(47,657)	$10,164	$ 777	$ 63	$1,708	$ (1,269)	$11,443	$ (36,214)
Comprehensive income (loss) per share, basic and diluted	$ (0.44)	$ 0.09	$ 0.01	$ -	$ 0.02	$ (0.01)	$ 0.11	$ (0.33)

Tabular amounts in thousands of Canadian dollars, except as noted

Reconciliation of Shareholders' Equity from Canadian GAAP to IFRS

(unaudited)

	Share Capital	Contributed Surplus	Accumulated Deficit	Accumulated Other Comprehensive Income	Shareholders' Equity
Canadian GAAP balances, June 30, 2010	$ 777,905	$ 9,064	$ (292,921)	$ -	$ 494,048
IFRS – 1 Elections *(note d)*	-	978	(3,608)	2,554	(76)
IFRS – 2 Share Based Payments *(note c)*	-	(777)	777	-	-
IAS – 37 Provisions *(note d)*	-	-	84	-	84
IFRS – 6 Exploration and Evaluation *(note f)*	-	-	(2,820)	-	(2,820)
IAS – 16 Property and Equipment *(note b)*	-	-	14,070	-	14,070
IAS – 21 The Effects of Changes in Foreign Currency *(note e)*	-	-	(898)	(442)	(1,340)
IAS – 12 Income Taxes *(note g)*	-	-	(1,882)	-	(1,882)
IFRS balances, June 30, 2010	$ 777,905	$ 9,265	$ (287,198)	$ 2,112	$ 502,084

Notes to the Canadian GAAP to IFRS Reconciliations of Total Comprehensive Income for the three and six months ended June 30, 2010 and Shareholders' Equity as at June 30, 2010

a) IFRS 1 – Elections Taken at First Adoption

IFRS 1 exemptions with a financial impact on the Company's accumulated deficit

	Accumulated Deficit
Canadian GAAP balance, January 1, 2010	$ (6,298)
IFRS 1 exemptions elected by the Company:	
• Cumulative translation adjustment - Tunisia	(2,554)
• Cumulative translation adjustment - UK	(13,686)
• Share-based compensation	(979)
• Decommissioning liability	(75)
IFRS balance, January 1, 2010	$ (23,592)
• "Return on equity" on Bridge Energy ASA distribution	13,686
Total financial impact of IFRS 1 exemptions	$ (3,608)

Under IFRS 1 "First Time Adoption of International Financial Reporting Standards", IFRS is applied to all accounts retrospectively at the Transition Date unless a specific exemption was available and taken. The following are the exemptions with a financial and non-financial impact on the Company's accounts that it has elected to apply:

IFRS 1 – Exemptions with a financial impact on the Company's accounts:

- Cumulative translation differences – The Company elected to set the cumulative translation account, which is included in accumulated other comprehensive loss, to nil at the Transition Date. During May 2010, the Company distributed its holdings in Bridge Energy ASA ("Bridge Energy"), to the Company's shareholders which resulted in a charge to its retained earnings of $232 million. Bridge Energy partially held the Company's United Kingdom – North Sea operations on which the Company had reported $13.7 million in accumulated other comprehensive losses immediately prior to the Transition Date. As the Company elected on the Transition Date to apply the IFRS 1 exemption whereby all cumulative foreign exchange losses are moved to its deficit account, the Company also made an adjustment to the distribution of its holdings in Bridge Energy to its shareholders by decreasing the loss by $13.7 million as offset in accumulated other comprehensive losses. Further as a result of IAS 21, The Effects of Changes in Foreign Exchange Rates (see Note 14 (e)), the Company recognized $2.6 million of cumulative currency exchange losses as at the Transition Date related to its Tunisian segment. The Company elected as at the Transition Date to remove these Tunisian segment's cumulative currency exchange losses that would have been reportable as accumulated other comprehensive losses and, accordingly, increase the deficit.

- Share-based compensation – The Company has elected not to apply IFRS 2 "Share-Based Payments" to options which vested before the Transition Date. As such, a $1.0 million increase in the deficit was made for options that were granted before the Transition Date but had not vested, with an offsetting increase in contributed surplus.
- Decommissioning liability – In accounting for changes in obligations to dismantle, remove and restore items of development and production assets, the guidance under IFRS requires changes in such obligations to be added to or deducted from the cost of the asset to which it relates. The adjusted depreciable amount of the asset is then depreciated prospectively over its remaining useful life. Rather than recalculating the effect of all such changes throughout the life of the obligation, the Company has elected to measure the liability and the related accretion effects at the Transition Date which had the effect of increasing the decommissioning liability by $0.1 million, with an offsetting increase to the deficit.

IFRS 1 – Significant exemptions without a financial impact on the Company's accounts:

- Deemed cost exemption for development and production and exploration and evaluation assets – The Company has elected to report these assets on the Transition Date at the deemed Canadian GAAP net carrying value versus retroactive application of IFRS. Crude oil and natural gas assets that were part of the full cost pool and determined to be developed or production assets under Canadian GAAP were allocated to Cash Generating Units pro rata using reserve values, subject to an impairment test on the Transition Date to IFRS.
- Business Combinations – the Company applied the exemption to not retrospectively report IFRS 3 Business Combinations for any business combinations prior to the Transition Date.

b) IAS 16 Adjustments – Property and Equipment

Under Canadian GAAP, a gain or loss on disposition of properties is reported when the subsequent full cost depletion rate changes by 20% or more, otherwise the proceeds of the property sale reduce the full cost pool. Under IFRS, any differences from proceeds of the property sale relative to its net book value are reported as either gains or losses. For the three and six months ended June 30, 2010, the Company sold properties which did not change its full cost depletion rate by at least 20% under previous Canadian GAAP but resulted in IFRS reportable gains of $12.5 million.

Upon transition to IFRS, the Company adopted a policy of depleting crude oil and natural gas assets on a unit-of-production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units-of-production over proved reserves. In addition, IFRS requires depletion to be calculated at a components' level where such components have similar economic lives whereas under Canadian GAAP the depletion calculation was calculated on the Company's petroleum and natural gas assets at a geographic level. As a result of these differences between IFRS and Canadian GAAP, the Company recognized a $1.3 million and $1.6 million decrease in its depletion expense, as reported within the line item depletion, depreciation and amortization, for the three and six months ended June 30, 2010, respectively.

c) IFRS 2 Adjustments – Share-Based Payments

For the three and six months ended June 30, 2010, under IFRS the Company recognized decreases in stock-based compensation relative to that reported under Canadian GAAP of $1.3 million and $0.7 million, respectively. During the three and six months ended June 30, 2010, the extent of certain employees' forfeited options resulted in an IFRS adjustment related to the additional recovery of the higher fair valued options as determined at the Transition Date. Share-based compensation for the three and six months ended June 30, 2010 also decreased under IFRS due to the inclusion of forfeiture estimates, as based on historical forfeitures, in the redetermination of the fair value of granted options during these periods in addition to the unvested outstanding options at the Transition Date relative to Canadian GAAP where forfeitures of awards were recognized only as they occurred. These decreases in share-based compensation for the three and six months ended June 30, 2011, under IFRS, relative to Canadian GAAP, were partially offset by increases in share-based compensation on the higher fair valued options as determined at the Transition Date.

d) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets

Under Canadian GAAP, accretion expense was included in the line item depletion, depreciation and accretion whereas under IFRS, accretion expense related to the decommissioning liability is included in the line item financing expenses resulting in the reclassification of $0.6 million and $0.8 million for the three and six months ended June 30, 2010, respectively. Further, under Canadian GAAP decommissioning liabilities were discounted at the Company's credit adjusted risk free rate of 8.5% whereas under IFRS the estimated cash flow to abandon and remediate wells and facilities has been risk adjusted resulting in the use of a risk free discount rate of 3% to 4%. The lower discount rate applied to the decommissioning liability under IFRS relative to Canadian GAAP resulted in lower accretion expense of $0.1 million for both the three and six months ended June 30, 2010 as reported in the line item financing expenses, of $0.5 million and $0.7 million, respectively.

e) IAS 21 Adjustments – The Effects of Changes in Foreign Exchange Rates

Under IFRS, the functional currency of a subsidiary or branch is determined by focusing on the primary economic environment in which it operates with less emphasis placed on factors such as the financing from and operational involvement of the consolidated reporting entity. This resulted in the Company's Tunisian operations being assessed as having a U.S. dollar functional currency versus the Company's Canadian dollar reporting currency. As such, the foreign exchange gains or losses that arise between the translation of the Tunisian operational results and Statement of Financial Position into the Company's reporting currency are recognized in other comprehensive income. Previously, under Canadian GAAP, the Company considered its Tunisian operations as integrated whereby only exchange differences between the monetary net assets and operational results were reported as foreign exchange gains or losses.

The application of IAS 21 resulted in adjustments to the following accounts:

Other Comprehensive Income and Accumulated Other Comprehensive Income (Loss)

For the three and six months ended June 30, 2010, under IFRS, the Company reported a $4.7 million and $2.1 million foreign currency translation adjustment as other comprehensive income, respectively, upon the revaluation of its Tunisian operational results and statement of financial position. When other comprehensive income of $2.1 million for the six months ended June 30, 2010 is combined with the $2.5 million cumulative foreign currency exchange losses resulting from the retroactive implementation of IAS 21 on the Transition Date, the Company reported a reconciling loss on its Tunisian operations from Canadian GAAP to IFRS in accumulated other comprehensive income (loss) as included in shareholders' equity of $0.4 million.

Foreign Exchange Gain (Loss)

The Company, under Canadian GAAP, recognized foreign exchange gains of $1.6 million and $0.9 million for the three and six months ended June 30, 2010, respectively, on the revaluation from US dollar denominated monetary net assets to Canadian dollars. The Company reversed these Canadian GAAP foreign exchange gains for the three and six months ended June 30, 2010 as under IFRS foreign exchange gains between the revaluation of the Tunisian net assets and operational results are reported through other comprehensive income.

f) IFRS 6 Adjustments – Exploration and Evaluation Assets

Under IFRS, the Company has selected an accounting policy whereby exploratory lands will be amortized over the life of the lease term (generally five year terms in Canada) in addition to geological and geophysical and other exploration costs concomitant to such lands. Under IFRS, the Company has also selected the accounting policy to expense all exploratory dry holes as incurred. Under Canadian GAAP, the Company followed the full cost method of accounting for its petroleum and natural gas interests whereby all exploration costs were capitalized and accumulated within geographic cost centres. For the three and six months ended June 30, 2010, under the Company's IFRS 6 accounting policies, a $2.8 million prospecting and exploration expense was reported in both periods which mostly pertained to geological and geophysical costs incurred on the Company's Tunisian exploration lands as previously capitalized to Property, plant and equipment under Canadian GAAP.

g) IAS 12 Adjustments – Income Taxes

The Company has recognized a $1.9 million deferred income tax expense for both the three and six months ended June 30, 2010, resulting from changes in its accounting bases due to the aforementioned IFRS adjustments.

CORPORATE INFORMATION

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Robert J. Herdman [(1)]
Townes G. Pressler Jr.
P. Grant Wierzba [(2)]

[(1)] Members of the Audit Committee
[(2)] Members of the Reserves, Safety and Environmental Committee
[(3)] Members of the Compensation, Nominating and Corporate Governance Committee

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ABBREVIATIONS

boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls	barrels
bbls/d	barrels per day
bop/d	barrels of oil per day
Brent	international market price for light crude oil blend
DGE	Tunisian Department of Energy
ETAP	Entreprise Tunisienne d'Activités Pétrolières
GJ	gigajoule
LIBOR	London Interbank Offered Rate
mcf	thousands of cubic feet
mcf/d	thousands of cubic feet per day
mmbbls	millions of barrels
mmcf	millions of cubic feet
mmcf/d	millions of cubic feet per day
STOIIP	Stock Tank Oil Initially In Place
WCSB	Western Canadian Sedimentary Basin

CONVERSION
Six thousand cubic feet (mcf) of natural gas equals one barrel of oil equivalent.