MANAGEMENT'S DISCUSSION AND ANALYSIS FOR THE YEAR ENDED DECEMBER 31, 2010

Contents

Management's Discussion and Analysis

Introduction

The following Management's Discussion and Analysis ("MD&A") was prepared at and is dated March 30, 2011. This MD&A reports on the financial condition and results of operations of Chinook Energy Inc. ("Chinook" or the "Company") for the three month period and years ended December 31, 2010, and 2009, and should be read in conjunction with the December 31, 2010, audited consolidated financial statements and notes as well as the annual audited consolidated financial statements and notes of Chinook (formerly Storm Ventures International Inc. ("SVI")) for the year ended December 31, 2009.

The consolidated financial position and results of operations include the accounts of the Company's direct and indirect wholly-owned subsidiaries.

The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are expressed in thousands of Canadian dollars, except per share and per unit amounts, and unless otherwise noted.

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 16.1 of this MD&A.

Discontinued Operations

Chinook's indirect wholly-owned subsidiary, Silverstone Energy Limited ("Silverstone"), combined with Bridge Energy Norge AS on March 26, 2010, whereby each of the companies became subsidiaries of a holding company, Bridge Energy ASA ("Bridge Energy"). Storm Ventures International (BVI) Limited (Chinook's wholly-owned subsidiary) ("SVI (BVI)") formerly owned all of the shares of Silverstone which contained Chinook's United Kingdom-North Sea business. On May 10, 2010, the Company, through its wholly-owned subsidiary, SVI (BVI) distributed all of the shares of Bridge Energy acquired to its shareholders such that the Company no longer has ownership in any assets or holdings in the North Sea. Operating results related to these assets have been included in net income from discontinued operations on the Consolidated Statements of Loss and Comprehensive Loss (see Note 17 of the audited annual consolidated financial statements).

The information contained in this MD&A relates to the continuing operations of the Company.

1. Business Overview

Chinook is headquartered in Calgary, Alberta, Canada and is a publicly-traded oil and natural gas exploration and production company with current operations focused in Canada and North Africa managed from offices in Calgary and Tunis, Tunisia. The Company resulted from the amalgamation of SVI and Iteration Energy Ltd. ("Iteration") pursuant to a plan of arrangement which closed on June 29, 2010. Through this plan of arrangement, Chinook acquired all of the issued and outstanding securities of Iteration and on July 6, 2010, was listed on the TSX.

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

- **Canada** – includes the Company's exploration for and development and production of oil, natural gas and natural gas liquids and other related activities within the Canadian cost centre.
- **Tunisia** – includes the Company's exploration for and development and production of oil, natural gas and other related activities within the Tunisian cost centre.
- **Corporate** – mainly includes general and administrative costs and assets held corporately.

All of the Company's production is sold to third-party customers. Segmented financial information is presented on an after-elimination of intercompany transaction basis.

The operational and financial risk factors that may impact the Company are included in section 11 of this MD&A.

2. Financial Summary

2.1. Financial and Operating Results

($ thousands, except per unit amounts)	Three months ended December 31 **2010**	Three months ended December 31 2009	Year ended December 31 **2010**	Year ended December 31 2009
Sales and prices [3]				
Oil sales *(bbl/d)*	**4,125**	93	**2,225**	68
Natural gas liquids sales *(bbl/d)*	**1,410**	-	**899**	-
Natural gas sales *(mcf/d)*	**62,346**	-	**40,282**	-
Average daily sales 6:1 *(boe/d)*	**15,927**	93	**9,839**	68
Average oil price *($/bbl)*	**76.49**	72.71	**73.13**	70.23
Average natural gas liquids price *($/bbl)*	**55.93**	-	**53.33**	-
Average natural gas price *($/mcf)*	**3.47**	-	**3.75**	-
Production [4]				
Oil *(bbl/d)*	**3,552**	93	**2,181**	68
Natural gas liquids *(bbl/d)*	**1,410**	-	**899**	-
Natural gas *(mcf/d)*	**62,346**	-	**40,282**	-
Average daily production *(boe/d)*	**15,354**	93	**9,795**	68
Financial operations				
Oil, gas and natural gas liquids revenue, net of royalties [3]	**47,227**	620	**114,620**	1,735
Cash flow [1]	**22,576**	(784)	**51,729**	(1,236)
Per share-basic and diluted [1]	**$ 0.11**	$ (0.01)	**$ 0.32**	$ (0.02)
Net loss from continuing operations	**(12,893)**	(1,332)	**(31,952)**	(5,999)
Per share-basic and diluted	**$ (0.06)**	$ (0.02)	**$ (0.20)**	$ (0.09)
Net loss	**(12,893)**	(16,327)	**(45,492)**	(19,617)
Per share-basic and diluted	**$ (0.06)**	$ (0.23)	**$ (0.28)**	$ (0.27)
Capital expenditures [2] [3]	**25,454**	3,692	**761,059**	7,983
Net debt [5]	**170,526**	(2,165)	**170,526**	(2,165)
Total assets	**805,732**	394,200	**805,732**	394,200
Common shares *(thousands)*				
Weighted average during period				
- basic	**214,188**	73,839	**162,003**	73,681
- diluted	**214,188**	73,839	**162,003**	73,681
Outstanding at period end				
- basic	**214,188**	75,224	**214,188**	75,224
- diluted	**227,603**	79,164	**227,603**	79,164

(1) Cash flow is a non-GAAP measurement and is defined under the Non-GAAP Measures section of this MD&A.
(2) Includes asset retirement obligations incurred during the period and other non-cash acquisition allocations.
(3) Excludes discontinued operations.
(4) Production volumes differ from sales volumes in Tunisia where volumes of oil are stored as inventory until title, responsibility and risk of the oil transfer to a third party occurs.
(5) Net debt includes bank debt, both current and long-term, and working capital deficit (surplus).

2.2. Financial Highlights

Revenue, net of royalties, increased $46.6 million for the three months ended December 31, 2010 compared with the same period in 2009. The newly acquired Canadian assets from the corporate acquisition of Iteration combined with the additional West Central Alberta assets acquired earlier in 2010, resulted in this substantial increase over the prior year which only consisted of sales in Tunisia.

Cash flow for the three months ended December 31, 2010, increased $23.4 million compared with same period in 2009. The increase is attributable primarily to the increased sales volumes from the recent acquisitions.

The net loss from continuing operations for the three months ended December 31, 2010, increased $11.6 million as a result of higher depletion charges and production expenses associated with the new production base, higher general and administrative costs associated with the corporate growth and transition to a publicly-traded company and higher interest charges related to the new debt.

For the year of 2010, revenue net of royalties increased by $112.9 million compared to the same period in 2009 substantially due to revenue from increased production volumes both through acquisition and drilling in Canada and Tunisia and higher commodity prices.

In 2010, cash flow increased by $53.0 million ($0.33 per share) compared to the same period in 2009. The increase was primarily attributed to increased volumes and higher commodity prices. Crude oil prices increased by 4% to $73.13/boe in 2010 from $70.23/boe in the comparable period in 2009.

The net loss from continuing operations for the full year of 2010 increased by $25.9 million, mainly as a result of higher general and administrative expenses, interest and financing charges and depletion over the comparable period in 2009.

As at December 31, 2010, the Company had long-term bank debt of $167.8 million compared with $179.8 million at September 30, 2010 and combined current and long-term debt of $19.3 million at December 31, 2009.

2.3. Operational Performance

Production volumes averaged 15,354 boe/d for the fourth quarter of 2010. Total sales volume for the fourth quarter of 2010 of 15,927 boe/d, a 15,834 boe/d sales volume increase over the same period in 2009, reflected the newly acquired Canadian and international operations.

Production volumes for the full year of 2010 averaged 9,795 boe/d compared to 68 boe/d in 2009. The majority of the increase in production was the result of production post-acquisition of Iteration midway through the year and from the Canadian and Tunisian assets acquired in the first quarter of 2010. Sales volumes for the full year of 2010 averaged 9,839 boe/d, again reflecting the impact of the property and corporate acquisitions completed mid-way through the year.

The difference between the Company's production and sales volumes arises from the operations in Tunisia where oil is stored in onshore tanks until shipping tankers are contracted for shipment. The Company has been able to maintain normal operations on a day-to-day basis inspite of the recent political turmoil in both Tunisia and its neighbouring countries.

2.4. Operational Highlights

The Company focused on the following projects in 2010:

Canada

On March 1, 2010, SVI completed, effective October 1, 2009, the acquisition of oil and natural gas assets located in west central Alberta from certain wholly-owned subsidiaries of Provident Energy Trust, for a total purchase price of approximately $175 million after interim adjustments (the "West Central Property Acquisition"). The acquired assets consisted mainly of low decline, liquids rich natural gas. The key producing areas acquired included: Brazeau, Gilby, Lochend, Jarrow and Whitecourt. Approximately 25% of the production was from unit interests and 50% was operated. The total purchase price of the asset acquisition was funded by the gross proceeds of $150 million from the equity financing to the Alberta Investment Management Corporation ("AIMCo") completed on March 1, 2010, with the remainder funded by bank debt and interim period cash flow.

On June 29, 2010, SVI acquired all of the outstanding securities of Iteration and amalgamated with Iteration to form Chinook Energy Inc. pursuant to the corporate acquisition of Iteration. In connection with the completion of the corporate acquisition of Iteration, SVI received a bridge loan of $167.8 million from AIMCo. Concurrent with the completion of the corporate acquisition of Iteration, Chinook repaid $150 million of the bridge loan in full by transferring to nominees of the lender all of the limited partnership units of a limited partnership which held an undivided 25.45% working interest in all of the assets of Iteration as at June 29, 2010. Pursuant to a management and administration agreement with the general partner of the limited partnership, Chinook administers the transferred Iteration assets held by the limited partnership on behalf of the general partner of the limited partnership. Also at closing of the corporate acquisition of Iteration, a new $240 million syndicated bank facility was put in place to replace SVI's and Iteration's prior bank facilities consisting of a $215 million revolving term credit facility and a $25 million operating credit facility.

On June 30, 2010, Chinook completed the acquisition of oil and natural gas properties in the Gilby area of west central Alberta from an intermediate producer for $46.25 million, before closing adjustments (the "Gilby Property Acquisition"). The Gilby Property Acquisition was funded with a portion of the proceeds received by Chinook from the sale of $24.3 million of non-core assets and from Chinook's credit facility. The Gilby Property Acquisition added high working interest, operated oil, natural gas and natural gas liquids production and reserves as well as undeveloped land. A significant portion of the acquired production was located within existing Chinook core production areas.

In the last half of 2010, the Company consolidated its understanding of the acquired assets and began a rationalization process of non-core producing properties that has continued into 2011.

Tunisia

The following is a summary of the significant corporate events in Chinook's Tunisian business segment over the last year.

On March 11, 2010, Storm Ventures International (Barbados) Limited, an indirect wholly-owned subsidiary of Chinook, acquired, effective January 1, 2009, all of the shares of Talisman Resources (Tunisia) Ltd. ("TRTL") (subsequently renamed Storm Sahara Limited), an indirect wholly-owned UK subsidiary of Talisman Energy Inc., for USD $18 million plus working capital. TRTL owned Tunisian assets consisting of an interest in a permit which has been divided into a producing area named the Adam concession and an exploration block named the Borj El Khadra exploration permit ("Borj El Khadra"). TRTL held a 5% non-operated interest in the Adam concession and a 10% non-operated interest in the Borj El Khadra permit (subject to an obligation to pay costs incurred, varying from 5% to 10%, depending upon Enterprise Tunisienne d'Activitiés Pétrolières ("ETAP") participation).

On March 16, 2010, Storm Ventures International (Barbados) Limited acquired an additional 15% interest in the Sud Remada production sharing contract for USD $4 million, resulting in SVI indirectly holding an 86% interest in this concession.

On a concession basis, the following operational updates occurred in 2010:

Sud Remada – During 2010, the Company increased its working interest in the producing area from 71% to 86% effective February 1, 2010, through the purchase of a 15% working interest from a partner. Production from the TT-2 discovery well continued on pace with management's expectations. An additional appraisal well, TT-3, was spud November 17, 2010. The well reached total depth of 1,555 metres on December 15, 2010 and was suspended on December 22, 2010 with the completion to be performed in early 2011. The well results were incorporated into the Plan of Development which was submitted to ETAP to accompany the request for a production concession in March 2011.

Jenein – The JC#1 commitment well, a 4,334 metre test well, was spud on May 27, 2010, and the rig was released on August 8, 2010, with Chinook retaining a 65% operated interest. The well has been suspended following an unsuccessful completion attempt. The well will likely be re-entered at a later date post-evaluation and a completion will be attempted on the secondary target, which is prospective for gas and condensate.

Hammamet – The Fushia well completed drilling operations and the rig was released on June 25, 2010. The well was plugged and abandoned in accordance with the pre-drill plan. The well was a potential discovery in the Miocene Birsa Formation and recovered volatile oil on an MDT test of a 16 metre pay interval. Development scenarios and their respective costs, timing and the resulting economics are currently being collected and analyzed by the Company and its partners. Completion of the well operation fulfills all work requirements on the Hammamet block.

Adam –The Company participated in drilling of the Karma 3 Acacus development well. The well was spud on April 29, 2010 and rig released on July 18, 2010. The result is a producing oil well on production commencing September 21, 2010.

Borj El Khadra – During 2010, 850 square kilometres of 3D seismic was shot to evaluate the Acacus oil potential. This 3D data was used in conjunction with previously acquired 3D data to assist in determining the next exploration well that was to be drilled by the end of 2010. Due to rig availability the well was spud on January 19, 2011. This well will fulfill the current work commitment on the permit and support a concession application later in 2011.

3. Capabilities to Deliver Results

3.1. Liquidity

The Company is subject to a declining asset base, as are all companies in the oil and natural gas production business, and therefore relies on ongoing development, exploration and acquisitions to replace and grow its reserve base.

It is not possible to predict, with any degree of confidence, future commodity prices given the economic environment and its impact on the demand for natural gas and crude oil. Should current conditions continue, cash flow may be affected and may impact the Company's ability and timing to develop proved and probable reserves necessary to maintain or achieve production growth.

Chinook generally relies on operating cash flows and its credit facilities to fund capital requirements and manage liquidity. The following table shows how the Company financed its business activities:

($ thousands)	**2010**	2009
Net cash from (used in)		
Operating activities	**$ 61,703**	$ 18,457
Financing activities	**431,538**	(9,960)
Investing activities	**(477,357)**	(20,880)
Foreign exchange, cash and cash equivalents	**(716)**	(3,955)
Increase (decrease) in cash and cash equivalents	**$ 15,168**	$ (16,338)

As is typical in the oil and natural gas industry, there is a timing difference between cash receipts from sales transactions and partner's share of capital costs and payments of trade payables. The Company closely monitors its credit risk and exposure to certain counterparties and makes adjustments where permitted under contractual terms.

The Company completed three private placements during 2010, for gross proceeds of $288.6 million. The first one closed in January at a price of $3.00 per share and gross proceeds of $13.5 million. The second placement closed in March in conjunction with the acquisition of certain Canadian oil and natural gas properties. The shares were issued at a price of $3.50 per share and gross proceeds of $150.0 million. The third placement was in the form of a subscription receipts issuance which closed on May 27, 2010. There were 38.5 million subscription receipts that were issued at a price of $3.25 per receipt for gross proceeds of $125.0 million. The proceeds from the subscription receipts were held in trust until June 29, 2010, when the funds were used for the purchase of all of the outstanding securities of Iteration and the subscription receipts were exchanged for common shares in Chinook.

On June 28, 2010, the Company entered into a $167.8 million bridge credit facility. The facility was used to help fund the acquisition of Iteration. On June 29, 2010, the Company made a one time in-kind payment on the drawn amount through the transfer to nominees of the lender of all of the limited partnership units of a limited partnership which held a 25.45% working interest in all of the Iteration properties. The in-kind payment reduced the drawn amount by $150.0 million. On August 9, 2010, the Company repaid the remaining balance of the bridge credit facility of $17.8 million from the proceeds on non-core asset sales.

On June 28, 2010, Chinook re-negotiated the credit facility to facilitate closing the acquisition of Iteration and for general corporate purposes. The total revolving credit facility available was $215.0 million, consisting of a $190.0 million revolving term credit facility and a $25.0 million operating facility. On June 30, 2010, the total revolving credit facility was increased to $240.0 million as a result of the additional Western Canadian assets purchased. The revolving period for the credit facility will end on June 27, 2011, unless extended for an additional 364 day period. The borrowing base was subject to a re-determination which was completed on December 22, 2010, resulting in the extendible revolving credit facility being amended to $230.0 million consisting of a $205.0 million revolving term credit facility and a $25.0 million operating facility.

The re-determination at December 22, 2010, brought the Tunisian assets into the borrowing base; however certain due diligence and the delivery of certain guarantees and security documents were not completed at that time. Subsequently, all required guarantees and security documents have been executed and delivered and due diligence by the banks' legal counsel has been completed; however the registration of security in the various jurisdictions and certain other usual and customary documentary conditions precedent have not been completed. These matters are expected to be completed in April 2011 and upon completion the revolving term credit facility will be increased to $240.0 million, consisting of a $215.0 million revolving credit facility and a $25.0 million operating facility.

At December 31, 2010, outstanding debt totaled $167.8 million, which is classified as long-term given the 364 day revolving period, or if not extended, the 364 day term loan conditions. Bank debt was comprised as follows:

($ thousands)	**2010**	2009
Revolving term credit facility	**$ 167,793**	$ -
Royal Bank of Scotland - current portion [(1)]	**-**	8,170
Royal Bank of Scotland [(1)]	**-**	11,166
Total	**$ 167,793**	$ 19,336

[(1)] This was associated with Silverstone and formed the discontinued operations at December 31, 2010. It is no longer part of the consolidated debt.

At December 31, 2010, the Company had cash and cash equivalents of $23.2 million held in current accounts predominantly located in Canada and Tunisia. Chinook anticipates it will have adequate liquidity in 2011 to fund its financial liabilities as repayments come due.

As an added layer of protection of its cash flow, the Company's commodity price risk management contracts provide price protection on approximately 14% of its estimated annual production for 2011. Chinook maintains a commodity price risk management program focused on maintaining sufficient cash flow to support its operations. The Company has entered into commodity price contracts for both natural gas and crude oil (section 5.1).

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 progress 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 obligations associated with financial commitments and future development costs on oil and natural gas properties from cash flow generated from the Canadian and Tunisian operations and by utilizing the undrawn funds from the credit facility. The Company had no defaults or breaches on its bank debt or any of its financial liabilities.

Contractual Obligations

In the normal course of business, Chinook is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

($ thousands)	2011	2012-13	2014-15	Thereafter	Total
Long-term debt and interest	$ -	$ 177,251	$ -	$ -	$ 177,251
Operating leases, net of recovery	1,907	3,768	1,025	-	6,700
Total	$ 1,907	$ 181,019	$ 1,025	$ -	$ 183,951

4. Strategic Plan and Outlook

4.1. 2010 Results and 2011 Guidance

	2010 H2 Guidance	2010 Results	2011 Guidance
Production - boe/d	15,800 - 15,900	15,722	16,700 - 17,100
Cash flow - millions	$ 55 - 60	$ 53	$ 130 - 140
Capital expenditures - millions	$ 55 - 60	$ 58	$ 120
Tunisia %	10 - 20	21	30
Debt outstanding - millions	$ 160 - 165	$ 167.8	$ 140 - 150
Operating expenses - per boe	$ 12.50	$ 12.34	$ 12.00
G&A - per boe	$ 3.00	$ 3.12	$ 2.50

Cash flow was lower than guidance due to higher one-time administrative expenses associated with listing the company on the Toronto Stock Exchange and additional full-time and consultative staff working on the integration of the assets after the corporate acquisition on June 29, 2010. Capital expenditures were within the guidance range during the second half of 2010 and included capitalized G&A and a larger expenditure on pipeline and facility maintenance. The increased capital expenditures resulted in higher than projected debt levels at the end of 2010. Operating expenses were lower than guidance on a per unit basis as a result of efforts in the field to concentrate on efficiencies in operations.

2011 Guidance

Chinook anticipates production in 2011 will average between 16,700 and 17,100 boe/d after taking into account non-core asset sales. The production growth is expected to be realized more in the second half of 2011. This represents a 6-9% increase from the previously announced 2011 guidance range. The production mix for 2011 is expected to be approximately 41% oil and natural gas liquids and 59% natural gas.

Western Canada

Chinook's consolidated 2011 capital program will direct approximately 75% of capital 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 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 expects to complete 45 wells in Canada in 2011 of which 11 wells have been completed in the first quarter. 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 being actively evaluated with pilot steam-assisted gravity drainage projects by other operators that Chinook will follow and use to assist in assessing the commercial viability of its acreage.

Tunisia

In Tunisia, Chinook will focus its short-term spending on the commercialization of the TT discovery at Sud Remada. The recycle rate in Tunisia in 2010 supports expanded commitments of capital as soon as the initial appraisal results can be incorporated into the Plan of Development and Chinook receives regulatory approval. Chinook is planning for a five to six vertical development well program before year end 2011. The TT discovery on the Sud Remada permit in the Ghadames basin represents the Company's near term oil development focus and the key catalyst to unlocking the considerable remaining exploration potential of the 1.2 million acre permit. An independent resource assessment by InSite Petroleum Consultants Ltd. confirmed gross Discovered Petroleum Initially in Place ("DPIIP") of 297 mmbbls, 11% of which is estimated to be recovered. 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. Chinook expects to drill up to ten wells in Tunisia in 2011, including one to two development wells at Adam and two exploration wells at Borj El Khadra.

Chinook's Board of Directors have 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/mcf for natural gas and $82.00/bbl for oil.

4.2. 2010 Actual Results

($ thousands, except per unit amounts)	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Pricing				
Crude oil *($/bbl)*	**76.49**	72.71	**73.13**	70.23
Natural gas liquids *($/bbl)*	**55.93**	-	**53.33**	-
Natural gas *($/mcf)*	**3.47**	-	**3.75**	-
$USD/$Cdn exchange rate	**1.01**	1.06	**1.03**	1.14
Capital expenditures (2)				
Canada	**21,127**	-	**719,423**	-
Tunisia	**4,049**	3,672	**38,744**	7,822
Corporate	**278**	20	**2,892**	161
Production (4)				
Oil *(bbl/d)*	**3,552**	93	**2,181**	68
Natural gas liquids *(bbl/d)*	**1,410**	-	**899**	-
Natural gas *(mcf/d)*	**62,346**	-	**40,282**	-
Total *(boe/d)*	**15,354**	93	**9,795**	68
Financial metrics				
Operating netback *($/boe)* (1)	**20.10**	43.60	**19.29**	67.53
Cash flow (1)	**22,576**	(784)	**51,729**	(1,236)
Cash flow per share (1)	**0.11**	(0.01)	**0.32**	(0.02)

(1) *This is a non-GAAP measurement and is defined under the Non-GAAP Measures section of this MD&A.*
(2) *Excludes asset retirement obligations incurred during the period.*
(3) *Excludes discontinued operations.*
(4) *Production volumes differ from sales volumes in Tunisia where volumes of oil are stored as inventory until title, responsibility and risk of the oil transfer to a third party occurs.*

5. Business Environment Analysis

5.1. Commodity Prices

The Company's natural gas production in Western Canada is sold at prices that reflect the AECO daily index pricing. Natural gas liquids produced in association with natural gas are sold at prices based on the monthly spot postings at Edmonton, Alberta and Mont Bellevue, KS. Oil production is sold at prices based upon Edmonton par benchmark postings.

The Company's oil production in Tunisia is sold based on the average price for Brent oil quotations for the three days after loading onto shipping tankers.

The Company's natural gas production from the Adam concession in Tunisia is sold at a price based off a sulfurous fuel oil in the Mediterranean.

Benchmark Prices

	Three months ended December 31	Year ended December 31
Oil		
WTI *($USD/bbl)*	85.16	**79.56**
Edmonton par *($/bbl)*	80.33	**77.84**
Brent *($USD/bbl)*	86.54	**80.06**
Natural gas liquids		
Edmonton Pentanes Plus *($/bbl)*	78.61	**84.04**
Mont Bellevue, KS *($USD/bbl)*	68.04	**62.71**
Natural gas		
AECO *($/mcf)*	3.64	**4.00**
USD/Cdn	1.012	**1.030**

While hedging activities may have opportunity costs when realized prices exceed hedged pricing, 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 December 31, 2010, the Company had the following commodity price contracts in place, on which $0.9 million in unrealized net gains have been recorded. With the following contracts, the Company has price protected 14% of its estimated 2011 annual average production.

	Volume	Sell/Call	Buy/Put	Term
Natural gas - contract 1	4,500 *GJ/d*	$5.00/*GJ*	$6.40/*GJ*	January 1, 2011 to December 31, 2011
Natural gas - contract 2	3,800 *GJ/d*	$5.00/*GJ*	$7.70/*GJ*	January 1, 2012 to March 31, 2012
Natural gas - contract 3	2,000 *GJ/d*	$6.00/*GJ*	-	November 1, 2010 to October 31, 2011
Crude oil - contract 1	1,000 *bbl/d*		$85.80 *USD/bbl*	January 1, 2011 to December 31, 2011
Crude oil - contract 2	500 *bbl/d*		$85.70 *USD/bbl*	January 1, 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.

5.2. Fourth Quarter 2010 Sensitivities

Chinook's financial performance is affected by factors such as changes in commodity prices, exchange rates and interest rates. The analysis is based on business conditions and sales volumes during the twelve months ended 2010. The estimated impact of these factors on the Company's financial performance for the twelve months of 2010 is summarized in the following table:

($ thousands, except per unit amounts)	**Twelve months ended December 31, 2010 Net income**
Price changes	
Oil increased $5.00 USD/bbl	**3,134**
Natural gas increased $1.00/mcf	**9,536**
Interest rate changes	
Rate increased by 1%	**859**
Foreign exchange rate changes	
Change in USD/Cdn by 1%	**889**

6. Reserves

6.1. Boe Conversions

Barrels of oil equivalent (boe) amounts have been calculated using the energy equivalent conversion method, using a conversion rate of 6,000 cubic feet (mcf) of natural gas to one barrel of oil and natural gas liquids (6 mcf = 1 bbl). Boe may be misleading, particularly if used in isolation. A boe conversion rate of 6 mcf = 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not necessarily represent a valid equivalence at the wellhead.

6.2. Reserves Summary

2010 was an active acquisition year for the Company which saw the composition of its assets change from strictly international to a new domestic base and a revised international focus. In Canada, Chinook completed two material property acquisitions, several minor asset dispositions and completed the acquisition of Iteration. Internationally, the Company completed an acquisition of additional working interest in the Sud Remada project, a corporate purchase that brought the Company its first significant production and exposure to the prolific Acacus oil play in Southern Tunisia, and divested of its equity interest in its North Sea assets. As a result, 2009 reserves are not comparative.

- Proved reserves totaled 37.4 mmboe. The proved reserve life index ("RLI") is 6.6 years using fourth quarter 2010 production.
- Proved plus probable reserves totaled 62.5 million boe. The proved plus probable RLI is 11.1 years using fourth quarter 2010 production.
- Proved developed producing reserves represented 71.6% of proved reserves and 42.9% of proved plus probable reserves as at December 31, 2010.
- Gross DPIIP associated with the Bir Ben Tartar (TT) discovery on the Sud Remada permit in Tunisia is estimated to be 297 mmboe. Proven and probable reserves net to the Company of 3.6 mmboe represents the 39% Contractor's share of the 9.25 mmboe recoverable from the 23% of DPIIP to which proven and probable reserves have been assigned. In addition, possible reserves of 2.07 mmboe and a Best Case Contingent Resource estimate of 8.37 mmboe recoverable are attributable to Chinook's interest in a scenario with pool recovery of 11% of DPIIP. [1, 2]
- The all-in cost to add proved reserves was $19.63/boe, and for adding proved plus probable reserves was $14.60/boe. The all-in calculation reflects the result of Chinook's $697.5 million capital investment program as it takes into account the effect of acquisitions, dispositions, revisions plus the change in future development costs.
- The proved finding and development cost, as per NI 51-101 requirements, was $29.18/boe and the proved plus probable finding and development cost, as per NI 51-101 requirements, was $21.57/boe. The change in future development costs ("FDC") was included in the calculation and the effect of acquisitions, divestitures and revisions was excluded.

- The net asset value amounted to $1.07 billion which results in the estimated net asset value per diluted share (being 217.5 million shares) at December 31, 2010, being $4.91 per share, based on the net present value of proved and probable reserves, discounted at 10% before tax and after deducting year end total net debt and adding an estimated value for undeveloped land in Canada. On an after tax basis, with a similar 10% discount rate, the net asset value is $776.9 million or $3.55 per diluted share.
- Future development costs were $168.6 million on a proved basis and $337.8 million on a proved plus probable basis.
- The Company established a recycle ratio on a proven plus probable reserve basis, before commodity price contracts, of 1.1 times in Canada and 3.9 times in Tunisia.

(1) "***Discovered Petroleum Initially-In-Place***" (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. "***Contingent Resources***" are defined in the COGE Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The Contingent Resources estimates and the DPIIP estimates are estimates only and the actual results may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources except to the extent identified as proved or probable reserves. ***Best Case Estimate***: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

(2) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

6.3. 2010 Reserves and Valuation

Gross and Net Company Interest Reserves as at December 31, 2010

The following table summarizes the Company's gross and net interest reserve volumes utilizing McDaniel's forecast pricing and cost estimates at December 31, 2010.

	Light and medium oil		Heavy oil		Associated and non-associated natural gas		Natural gas liquids		Oil equivalent (6:1)	
Reserves category	Gross [1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mmcf)*	Net [2] *(mmcf)*	Gross[1] *(mbbl)*	Net [2] *(mbbl)*	Gross [1] *(mboe)*	Net [2] *(mboe)*
Canada										
Proved										
Developed producing	5,745	4,837	336	322	106,876	89,527	2,332	1,688	26,224	21,768
Developed non-producing	691	589	60	53	11,586	9,819	183	132	2,865	2,411
Undeveloped	735	622	-	-	7,645	6,389	184	152	2,193	1,839
Total proved	7,170	6,049	396	375	126,107	105,736	2,698	1,972	31,283	26,017
Probable additional	3,261	2,636	162	147	59,348	48,710	1,207	870	14,520	11,770
Total proved plus probable	10,432	8,683	558	522	185,455	154,445	3,905	2,841	45,803	37,787
Tunisia										
Proved										
Developed producing	423	365	-	-	794	717	-	-	555	485
Developed non-producing	404	382	-	-	1,181	1,043	-	-	601	555
Undeveloped	4,491	4,161	-	-	2,921	2,656	-	-	4,977	4,603
Total proved	5,317	4,908	-	-	4,896	4,415	-	-	6,133	5,643
Probable additional	10,218	9,208	-	-	1,826	1,637	-	-	10,522	9,481
Total proved plus probable	15,535	14,115	-	-	6,721	6,052	-	-	16,655	15,124
Total company										
Proved										
Developed producing	6,168	5,202	336	322	107,669	90,244	2,332	1,688	26,780	22,253
Developed non-producing	1,095	971	60	53	12,767	10,862	183	132	3,465	2,966
Undeveloped	5,225	4,783	-	-	10,566	9,045	184	152	7,170	6,442
Total proved	12,487	10,956	396	375	131,002	110,151	2,698	1,972	37,416	31,661
Probable additional	13,479	11,843	162	147	61,174	50,347	1,207	870	25,043	21,251
Total proved plus probable	25,967	22,799	558	522	192,176	160,498	3,905	2,841	62,459	52,911

(1) *Gross reserves are the company's working interest reserves before royalty deductions and do not include royalty interest volumes.*
(2) *Net reserves are after royalty deductions and include royalty interest volumes.*

Net Present Value Summary (before tax) as at December 31, 2010

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPVs include a deduction for estimated future well abandonment costs in respect of wells for which reserves have been assigned.

($ thousands except per unit amounts)	Net present values of future net revenue before income taxes discounted at *(%/year)*					Unit value before income taxes discounted at 10%	
Reserves category	0%	5%	10%	15%	20%	*($/boe)*	*($/mcfe)*
Canada							
Proved							
Developed producing	680,140	523,636	430,707	368,456	323,633	19.79	3.30
Developed non-producing	78,615	59,144	46,582	38,027	31,892	19.32	3.22
Undeveloped	60,440	44,589	34,088	26,750	21,415	18.54	3.09
Total proved	819,194	627,369	511,377	433,233	376,939	19.66	3.28
Probable additional	466,310	280,051	191,441	141,202	109,529	16.26	2.71
Total proved plus probable	1,285,505	907,420	702,818	574,434	486,468	18.60	3.10
Tunisia							
Proved							
Developed producing	29,825	27,062	24,782	22,888	21,299	51.14	8.52
Developed non-producing	30,753	24,528	20,156	16,970	14,571	36.29	6.05
Undeveloped	146,907	117,345	95,078	77,685	63,772	20.65	3.44
Total proved	207,484	168,935	140,017	117,543	99,642	24.81	4.14
Probable additional	530,461	422,124	342,782	282,072	234,706	36.16	6.03
Total proved plus probable	735,945	591,059	482,798	399,615	334,348	31.92	5.32
Total company							
Proved							
Developed producing	709,965	550,698	455,489	391,345	344,932	20.47	3.41
Developed non-producing	109,368	83,672	66,739	54,997	46,463	22.50	3.75
Undeveloped	207,347	161,933	129,166	104,435	85,187	20.05	3.34
Total proved	1,026,178	796,304	651,393	550,776	476,582	20.57	3.43
Probable additional	996,771	702,175	534,223	423,274	344,235	25.14	4.19
Total proved plus probable	2,021,450	1,498,479	1,185,615	974,049	820,816	22.41	3.73

Note: Columns may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2010

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPVs include a deduction for estimated future well abandonment costs in respect of wells for which reserves have been assigned.

($ thousands except per unit amounts)	Net present values of future net revenue after income taxes discounted at *(%/year)*					Unit value after income taxes discounted at 10%	
Reserves category	0%	5%	10%	15%	20%	*($/boe)*	*($/mcfe)*
Canada							
Proved							
Developed producing	642,122	498,447	412,454	354,417	312,346	18.95	3.16
Developed non-producing	58,289	44,833	36,034	29,997	25,626	14.95	2.49
Undeveloped	42,380	30,046	21,894	16,220	12,111	11.91	1.98
Total proved	742,791	573,326	470,382	400,663	350,083	18.08	3.01
Probable additional	347,175	208,583	142,562	105,129	81,549	12.11	2.02
Total proved plus probable	1,089,965	781,909	612,944	505,762	431,632	16.22	2.70
Tunisia							
Proved							
Developed producing	12,440	11,423	10,544	9,796	9,161	21.76	3.63
Developed non-producing	19,051	15,769	13,387	11,597	10,210	24.10	4.02
Undeveloped	108,062	86,046	69,132	55,746	44,943	15.02	2.50
Total proved	139,553	113,238	93,062	77,139	64,315	16.49	2.75
Probable additional	291,962	228,618	182,001	146,840	119,792	19.20	3.20
Total proved plus probable	431,515	341,857	275,064	223,979	184,106	18.19	3.03
Total company							
Proved							
Developed producing	654,562	509,870	422,997	364,213	321,507	19.01	3.17
Developed non-producing	77,340	60,602	49,421	41,594	35,836	16.66	2.78
Undeveloped	150,442	116,092	91,025	71,966	57,055	14.13	2.36
Total proved	882,343	686,564	563,444	477,773	414,398	17.80	2.97
Probable additional	639,137	437,202	324,563	251,969	201,340	15.27	2.55
Total proved plus probable	1,521,480	1,123,766	888,008	729,741	615,738	16.78	2.80

Note: Columns may not add due to rounding.

Gross Company Reserve Reconciliation for 2010

The following table is a reconciliation of the Company's gross interest reserves, before deduction of royalties payable, at December 31, 2010 and December 31, 2009 using McDaniel's forecast pricing and cost estimates as at December 31, 2010 and December 31, 2009.

	6:1 Oil equivalent *(mboe)*		
	Total proved	Probable	Proved plus probable
December 31, 2009 - opening balance	3,819	8,619	12,438
Additions and extensions	1,730	1,189	2,920
Improved performance	126	6	132
Discoveries	496	106	602
Acquisitions	34,784	14,738	49,522
Dispositions	-	-	-
Technical revisions	35	386	421
Production	(3,575)	-	(3,575)
December 31, 2010 - closing balance	37,416	25,043	62,459

Escalating Price and Cost Assumption Forecast as at December 31, 2010

The forecast price and cost assumptions take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the evaluations were the McDaniel forecast prices as follows:

	WTI crude oil *(USD$/bbl)*	Brent *(USD$/bbl)*	Edmonton light crude oil *(Cdn$/bbl)*	Henry Hub natural gas *(USD$/mmbtu)*	AECO natural gas *(Cdn$/mmbtu)*	Edmonton Condensate and natural gasoline *(Cdn$/bbl)*	Propane *(Cdn$/bbl)*	Butane *(Cdn$/bbl)*	USD/Cdn Exchange *(USD$/Cdn)*
2011	85.00	85.00	84.20	4.55	4.25	88.20	44.40	67.90	0.975
2012	87.70	87.20	88.40	5.30	4.90	90.40	47.70	71.20	0.975
2013	90.50	89.50	91.80	5.75	5.40	93.90	50.30	74.00	0.975
2014	93.40	92.30	94.80	6.30	5.90	96.90	52.70	76.40	0.975
2015	96.30	95.20	97.70	6.80	6.35	99.90	55.00	78.70	0.975
	90.58	89.84	91.38	5.74	5.36	93.86	50.02	73.64	0.975

(1) *Prices escalate at 2% per year after 2015.*

6.4. Future Development Costs

($ millions)	**2010**	2009
Proved		
Canada	**37.4**	-
Tunisia	**131.1**	135.9
Total proved	**168.6**	135.9
Proved plus probable		
Canada	**59.3**	-
Tunisia	**278.5**	252.3
Total proved plus probable	**337.8**	252.3

6.5. Recycle Ratio and Reserves Life Index

The recycle ratio is calculated as the netback per barrel divided by the finding and development costs (including acquisitions and dispositions). It is a measure of the profitability and efficiency of the Company.

The reserve life index was calculated using the Company's 2010 fourth quarter production average.

	Recycle ratio		Reserves life index	
	Proved reserves	Proved plus probable	Proved reserves *(years)*	Proved plus probable reserves *(years)*
Canada	0.8	1.1	5.8	8.5
Tunisia	4.0	3.9	24.7	66.9
Consolidated	1.0	1.3	6.6	11.1

6.6. Finding, Development and Acquisition Costs ("FD&A")

The following tables summarize the Company's FD&A costs for the year ended December 31, 2010, including future development costs.

NI 51-101 Finding and Development Costs

Total Proved Finding and Development Cost *($ thousands, except per unit amounts)*	**2010**
Capital expenditures excluding acquisitions and dispositions *(unaudited)*	**50,018**
Net change from previously allocated future development capital	**19,107**
Total capital including the net change in future capital	**69,125**
Reserve additions excluding acquisitions, dispositions and revisions *(mboe)*	**2,369**
Total proved finding and development costs *(per boe)*	**29.18**

Total Proved Plus Probable Finding and Development Cost *($ thousands, except per unit amounts)*	**2010**
Capital expenditures excluding acquisitions and dispositions *(unaudited)*	**49,151**
Net change from previously allocated future development capital	**30,026**
Total capital including the net change in future capital	**79,177**
Reserve additions excluding acquisitions, dispositions and revisions *(mboe)*	**3,670**
Total proved plus probable finding and development costs *(per boe)*	**21.57**

All-In Finding, Development and Acquisition Costs

Total Proved All-In Finding, Development and Acquisition Cost Including FDC, Acquisitions, Dispositions and Revisions *($ thousands, except per unit amounts)*	**2010**
Capital expenditures including acquisitions and dispositions *(unaudited)* [1]	**697,482**
Net change from previously allocated future development capital	**32,645**
Total capital including the net change in future capital	**730,127**
Reserve additions including acquisitions, dispositions and revisions *(mboe)*	**37,188**
All-in total proved finding and development costs *(per boe)*	**19.63**

[1] *Excludes non-cash costs, including asset retirement obligations.*

Total Proved Plus Probable All-in Finding, Development and Acquisition Cost Including FDC, Acquisitions, Dispositions and Revisions *($ thousands, except per unit amounts)*	**2010**
Capital expenditures including acquisitions and dispositions *(unaudited)* [1]	**697,482**
Net change from previously allocated future development capital	**85,489**
Total capital including the net change in future capital	**782,972**
Reserve additions including acquisitions, dispositions and revisions *(mboe)*	**53,612**
All-in total proved plus probable finding and development costs *(per boe)*	**14.60**

(1) *Excludes non-cash costs, including asset retirement obligations.*

FD&A costs on the crude oil and natural gas operations include all capital activities in which the Company participated including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post-closing and were increased by the amount of production from the closing date to December 31. FD&A cost on the disposed properties are based on the reserve evaluation as at December 31 of the year prior to the closing date and were decreased by the amount of production to the closing date.

6.7. Corporate Net Asset Value

The Company's net asset value as of December 31, 2010, is detailed in the following table. This net asset value determination is a "point-in-time" measurement and does not take into account the possibility of Chinook being able to recognize additional reserves through successful future capital investment in its existing properties beyond those included in the 2010 year-end reserve reports.

December 31, 2010	Before tax NPV 10%		Before tax NPV 15%	
	($ thousands)	*$/share*	*($ thousands)*	*$/share*
Proved plus probable reserves NPV [1,2]	1,185,615	5.54	974,049	4.55
Undeveloped acreage [3]	53,096	0.25	53,096	0.25
Net debt [4]	(170,526)	(0.80)	(170,526)	(0.80)
Net asset value (basic) [5]	1,068,184	4.99	856,618	4.00
Net asset value (diluted) [6]	1,074,520	4.91	862,954	3.94

December 31, 2010	After tax NPV 10%		After tax NPV 15%	
	($ thousands)	*$/share*	*($ thousands)*	*$/share*
Proved plus probable reserves NPV [1] [2]	888,008	4.15	729,742	3.41
Undeveloped acreage [3]	53,096	0.25	53,096	0.25
Net debt [4]	(170,526)	(0.80)	(170,526)	(0.80)
Net asset value (basic) [5]	770,577	3.60	612,311	2.86
Net asset value (diluted) [6]	776,913	3.55	618,647	2.83

(1) *Evaluated by independent reserve evaluators as at December 31, 2010. Net present value of future net revenue does not represent the fair market value of the reserves.*
(2) *Net present values for before and after tax are based on McDaniel's December 31, 2010 escalated price forecast.*
(3) *Undeveloped land value has been calculated based on internal estimates of $100/acre for all Canadian lands.*
(4) *Net debt as at December 31, 2010, including working capital deficit.*
(5) *Basic shares at December 31, 2010 total 214,187,681 common shares.*
(6) *Diluted shares at December 31, 2010, total 217,475,731 common shares which include in-the-money options of 3,288,050 shares with proceeds of $6.3 million.*

7. Results of Operations

7.1. Operations

Production

Three months ended December 31	2010				2009			
	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	**3,031**	**1,410**	**61,419**	**14,678**	-	-	-	-
Tunisia	**522**	**-**	**927**	**676**	93	-	-	93
Total	**3,553**	**1,410**	**62,346**	**15,354**	93	-	-	93

Year ended December 31	2010				2009			
	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	**1,744**	**899**	**39,614**	**9,247**	-	-	-	-
Tunisia	**437**	**-**	**668**	**548**	68	-	-	68
Total	**2,181**	**899**	**40,282**	**9,795**	68	-	-	68

Fourth Quarter

Average production in the fourth quarter of 2010 was 15,261 boe/d higher than the annual average production for 2009 as a result of:

- Production from the Canadian assets acquired in March 2010;
- Production from the Adam concession in Tunisia acquired in March 2010;
- Increased production in Sud Remada, Tunisia due to an increased working interest; and
- Production from Iteration assets acquired as a result of the corporate acquisition of Iteration in June 2010.

Twelve Months

Average production for the year 2010 grew 9,727 boe/d when compared to 2009, primarily due to the acquisition and amalgamation of assets in Canada and Tunisia.

Gross Revenue

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2010**	2009	**2010**	2009
Oil sales	**$ 29,027**	$ 620	**$ 59,403**	$ 1,734
Per *(bbl)*	**76.49**	72.71	**73.13**	70.23
Natural gas liquids sales	**7,254**	-	**17,506**	-
Per *(bbl)*	**55.93**	-	**53.33**	-
Natural gas sales	**19,890**	-	**55,100**	-
Per *(mcf)*	**3.47**	-	**3.75**	-
Total production revenue	**56,171**	620	**132,010**	1,734
Per *(boe)*	**$ 38.34**	$ 72.71	**$ 36.78**	$ 70.23

Fourth Quarter

Total gross production revenue increased $55.6 million in the fourth quarter when compared to the quarterly sales of 2009 as a result of:

- Production related to the acquisition of the Canadian assets in March 2010;
- Production from Iteration assets acquired as a result of the corporation acquisition in June 2010;
- Production from the acquisition of the Adam concession in Tunisia in March 2010;
- Crude oil sales in Tunisia from the Sud Remada field from production built up in the first quarter of 2010, at a higher working interest; and

Twelve Months

During 2010, gross revenues increased $130.3 million due to:

- Increased sales volumes with acquisition of assets in Canada and Tunisia;
- Increased sales volume in Sud Remada with the increased working interest from 71% to 86%;
- Increased sales volumes from the corporate acquisition of Iteration effective June 29, 2010; and

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2010**	2009	**2010**	2009
Total	**$ 8,944**	$ 303	**$ 17,390**	$ 1,428
Percent of revenue	**15.9**	7.5	**13.2**	6.4

There are no royalties incurred for Sud Remada as the operations are governed by a production sharing contract with ETAP, the Tunisian national oil company. Under the contract, the Company receives 62.625% of the production with ETAP receiving the remaining 37.375% of the production. The share that is received by ETAP is then used to pay the royalties and taxes on behalf of the Company.

Within the Adam concession in Tunisia, there is a royalty paid on oil and natural gas production which is based on a sliding scale calculation with royalty rates of 2-15%. Presently the Company is paying an average royalty rate of 9% for gas and 12% for 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.

Fourth Quarter

With increased production from the acquisitions of assets in Canada and Tunisia and the acquisition of Iteration, royalties in Canada for the fourth quarter of 2010, were 18.9% of Canadian revenue and in Tunisia 1.9% of Tunisian revenue.

Twelve Months

With increased production from the acquisitions of assets in Canada and Tunisia and the corporate acquisition of Iteration, royalties in Canada averaged 14.3% of Canadian revenue for the year and in Tunisia averaged 5.5% of Tunisia revenue for the year.

Production Expense

($ thousands, except per unit amounts)	Three months ended December 31 2010	2009	Year ended December 31 2010	2009
Total	**17,790**	248	**45,345**	733
Per sales *(boe)*	**$ 12.14**	$ 29.11	**$ 12.63**	$ 29.70

Fourth Quarter

Operating costs of $17.8 million ($12.14 per sales boe), were recorded in 2010, an increase of $17.5 million from $0.2 million ($29.11 per sales boe) recorded in 2009. The increased operating costs were primarily from the acquisitions of assets completed in the first quarter of 2010 and the additional production costs associated with the assets acquired as a result of the corporate acquisition of Iteration in June 2010. Operating costs in Canada averaged $12.31/boe while operating costs in Tunisia averaged $10.20/boe.

Twelve Months

In 2010, operating expenses increased $44.6 million with new production in Canada and increased production in Tunisia. Canada's operating costs averaged $12.45/boe while Tunisia averaged $15.39/boe.

General and Administration Expenses ("G&A")

($ thousands, except per unit amounts)	Three months ended December 31 2010	2009	Year ended December 31 2010	2009
Stock based compensation	**$ 1,709**	$ 1,089	**$ 6,233**	$ 2,999
Rent and general office costs	**1,766**	254	**4,187**	1,002
Staffing	**1,096**	219	**4,785**	1,039
Legal expenses	**227**	(104)	**2,003**	(60)
Accounting and audit costs	**763**	148	**1,085**	323
Corporate expenses	**1,312**	151	**5,227**	804
Total G&A	**6,873**	1,757	**23,520**	6,107
Per sales *(boe)*	**$ 4.69**	$ 205.38	**$ 6.55**	$ 246.06
Cash G&A	**5,164**	668	**17,287**	3,108
Per sales *(boe)*	**$ 3.52**	$ 78.05	**$ 4.82**	$ 125.21

Fourth Quarter

G&A expenses for the fourth quarter of 2010 were $5.1 million higher than the same period in 2009 due to:

- Increased office costs due to the additional office lease commitment associated with the acquisition of Iteration and office moves to integrate the acquisition;
- Increased staff costs associated with the increased Canadian and international producing assets;
- Increased legal expense relating to the amalgamation and formation of the new company; and
- Increased professional fees related to the preparation of financial statements to follow new accounting standards and year end audit and reserve evaluations.

Twelve Months

During 2010, G&A expenses increased $17.4 million mainly due to:

- Increased stock based compensation due to the granting of and modification of exercise prices of stock options held by employees, directors, officers and other service providers;

- Costs associated with the amalgamation and formation of Chinook;
- Increased personnel related costs as a result of higher staff levels to support the growth of the Company; and
- A change in accounting policy related to business combinations such that in 2009 costs associated with asset or corporate acquisitions were capitalized, but in 2010 the Company adopted the new Canadian Institute of Chartered Accountants ("CICA") Handbook section 1582 requiring these costs to be expensed.

Corporate Netbacks

The following tables outline the corporate netbacks by country for the twelve and three month periods ended December 31, 2010, and 2009. It should be noted that corporate general and administrative costs associated with head office are included in 2009 total corporate netbacks, which with the low sales volumes, skew per unit calculations.

Year ended December 31		**2010**			2009	
	Canada (2)	**Tunisia**	**Total**	Canada	Tunisia	Total (3)
Sales volumes						
Oil *(bbls/d)*	**1,744**	**481**	**2,225**	-	68	68
Natural gas liquids *(bbls/d)*	**899**	**-**	**899**	-	-	-
Natural gas *(mcf/d)*	**39,614**	**668**	**40,281**	-	-	-
Total sales *(boe/d)*	**9,247**	**592**	**9,839**	-	68	68
Per sales *(boe)*						
Realized sales price	**$ 34.01**	**$ 79.64**	**$ 36.76**	$ -	$ 70.23	$ 70.23
Royalties	**(4.87)**	**(4.35)**	**(4.84)**	-	-	-
Production expense	**(12.45)**	**(15.39)**	**(12.63)**	-	(29.70)	(29.70)
General and administration (1)	**(4.79)**	**(3.42)**	**(4.82)**	-	(29.31)	(154.07)
Corporate netback	**$ 11.90**	**$ 56.48**	**$ 14.47**	$ -	$ 11.22	$ (113.54)

(1) General and administration expenses by country exclude all non-cash stock based compensation.
(2) Canada also includes overall corporate general and administrative expenses associated with head office.
(3) Includes overall corporate general and administrative expenses associated with head office.

Three months ended December 31		**2010**			2009	
	Canada (2)	**Tunisia**	**Total**	Canada	Tunisia	Total (3)
Sales volumes						
Oil *(bbls/d)*	**3,031**	**1,094**	**4,125**	-	93	93
Natural gas liquids *(bbls/d)*	**1,410**	**-**	**1,410**	-	-	-
Natural gas *(mcf/d)*	**61,419**	**927**	**62,346**	-	-	-
Total sales *(boe/d)*	**14,678**	**1,249**	**15,927**		93	93
Per sales *(boe)*						
Realized sales price	**$ 34.30**	**$ 85.80**	**$ 38.34**	$ -	$ 72.71	$ 72.71
Royalties	**(6.49)**	**(1.60)**	**(6.10)**	-	-	-
Production expense	**(12.31)**	**(10.20)**	**(12.14)**	-	(29.11)	(29.11)
General and administration (1)	**(3.61)**	**(2.19)**	**(3.52)**	-	(13.85)	(127.82)
Corporate netback	**$ 11.89**	**$ 71.80**	**$ 16.58**	$ -	$ 29.75	$ (84.22)

(1) General and administration expenses by country exclude all non-cash stock based compensation.
(2) Canada also includes overall corporate general and administrative expenses associated with head office.
(3) Includes overall corporate general and administrative expenses associated with head office.

7.2. Capital Expenditures

Twelve Months

Capital Expenditures

Year ended December 31	2010 [4]				2009			
($ thousands) [1] [2]	**Canada**	**Tunisia**	**Corporate**	**Total**	Canada	Tunisia	Corporate	Total
Land and lease	**$ 3,443**	**$ -**	**$ -**	**$ 3,443**	$ -	$ 96	$ -	$ 96
Seismic and G&G	**1,374**	**2,096**	**-**	**3,470**	-	3,870	-	3,870
Drilling and completions	**32,024**	**15,671**	**-**	**47,695**	-	1,598	-	1,598
Abandonment	**3,418**	**-**	**-**	**3,418**	-	-	-	-
Facilities and equipment	**3,249**	**1,241**	**-**	**4,490**	-	-	-	-
Field expenditures	**43,508**	**19,008**	**-**	**62,516**	-	5,564	-	5,564
Capitalized G&A	**2,533**	**471**	**-**	**3,004**	-	2,212	-	2,212
Furniture and equipment	**-**	**-**	**2,892**	**2,892**	-	46	161	207
Property acquisitions [3]	**697,666**	**19,265**	**-**	**716,931**	-	-	-	-
Property dispositions	**(24,284)**	**-**	**-**	**(24,284)**	-	-	-	-
Total	**$ 719,423**	**$ 38,744**	**$ 2,892**	**$ 761,059**	$ -	$ 7,822	$ 161	$ 7,983

[1] *Excludes discontinued operations.*
[2] *Includes corporate acquisitions.*
[3] *Corporate acquisition of Iteration is net of the concurrent in-kind payment via the transfer of 25.45% of the Iteration assets to a lender.*
[4] *Includes non-cash items, such as asset retirement obligation and non-cash acquisition allocations.*

Wells Drilled

Year ended December 31, 2010	**Canada**		**Tunisia**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Oil	**8.00**	**4.11**	**1.00**	**0.65**	**9.00**	**4.76**
Gas	**4.00**	**1.75**	**-**	**-**	**4.00**	**1.75**
Dry	**-**	**-**	**1.00**	**0.35**	**1.00**	**0.35**
	12.00	**5.86**	**2.00**	**1.00**	**14.00**	**6.86**
Development						
Oil	**15.00**	**9.79**	**2.00**	**0.91**	**17.00**	**10.70**
Gas	**4.00**	**2.19**	**-**	**-**	**4.00**	**2.19**
Dry	**1.00**	**0.75**	**-**	**-**	**1.00**	**0.75**
	20.00	**12.73**	**2.00**	**0.91**	**22.00**	**13.64**
Total	**32.00**	**18.59**	**4.00**	**1.91**	**36.00**	**20.50**

The Company purchased producing oil and natural gas assets from a senior producer in Canada in the first quarter of 2010. The acquisition was the Company's entrance into the Western Canadian Sedimentary Basin with the assets being located in west central Alberta. Internationally, the Company acquired another company from a senior producer that held a non-operated 5% interest in the Adam concession in Tunisia and a non-operated 10% interest in the Borj El Khadra and also purchased another 15% interest in the Sud Remada field from an operating partner.

On June 29, 2010, Iteration was acquired via a plan of arrangement (see Note 3 of the audited annual consolidated financial statements). The Company also acquired oil and natural gas assets in west central Alberta on June 30, 2010. A program of property rationalization through the sale of non-core oil and natural gas assets in Alberta was started in early June 2010 and continued through the third quarter of 2010.

Fourth Quarter

Wells Drilled

Three months ended December 31, 2010	**Canada**		**Tunisia**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Oil	**-**	**-**	**1.00**	**0.86**	**1.00**	**0.86**
Gas	**1.00**	**0.26**	**-**	**-**	**1.00**	**0.26**
Dry	**-**	**-**	**-**	**-**	**-**	**-**
	1.00	**0.26**	**-**	**-**	**2.00**	**1.12**
Development						
Oil	**8.00**	**5.89**	**-**	**-**	**8.00**	**5.89**
Gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry	**1.00**	**0.75**	**-**	**-**	**1.00**	**0.75**
	9.00	**6.64**	**1.00**	**0.86**	**9.00**	**6.64**
Total	**10.00**	**6.90**	**1.00**	**0.86**	**11.00**	**7.76**

During the fourth quarter of 2010, the Company's capital expenditures were $25.4 million which was comprised mainly of $18.5 million related to drilling and completions, $4.1 million related to facilities, non-core property dispositions, Crown and freehold land purchases, with the balance relating to non-operated properties.

7.3. Cash Flow

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2010**	2009	**2010**	2009
Cash flow from continuing operations	**$ 22,576**	$ (784)	**$ 51,729**	$ (1,236)
Per share	**0.11**	(0.01)	**0.32**	(0.02)
Per sales *(boe)*	**15.41**	(45.84)	**14.40**	(49.80)

Fourth Quarter

Cash flow increased by $23.4 million in the fourth quarter of 2010, compared with the same period in 2009. The increase was as a result of:

- Increased production revenue and the related netbacks associated with the acquisition of Canadian assets in west central Alberta and the corporate acquisition of Iteration.

This was partially offset by:

- Increased interest and financing charges related to carrying a higher debt level; and
- Higher general and administrative expenses associated with increased personnel and corporate costs.

Twelve Months

During 2010, cash flow increased by $53.0 million mainly due to:

- Increased production revenue and related netbacks associated with the acquisition of Canadian producing properties and the acquisition of producing properties in Tunisia as well as an increase in working interest in the producing Sud Remada concession of Tunisia; and
- Higher realized gains on commodity derivative contracts.

This was partially offset by:

- Increased interest and financing charges related to obtaining credit facilities and the carrying of debt balances associated with property and corporate acquisitions;
- Increased general and administrative expenses related to additional personnel to manage the corporate growth and transition to a publicly-traded company; and
- Increased current taxes resulting from the corporate acquisition of TRTL, renamed Storm Sahara Limited.

7.4. Interest and Financing Charges

	Three months ended December 31		Year ended December 31	
($ thousands)	**2010**	2009	**2010**	2009
Canada	**$ 2,261**	$ -	**$ 11,551**	$ -
Tunisia	**(3)**	2	**9**	17
Corporate	**2**	(1)	**14**	3
Total	**$ 2,260**	$ 1	**$ 11,574**	$ 20

Fourth Quarter

Interest and financing charges increased $2.3 million in the fourth quarter of 2010, when compared with the same period in 2009 primarily as a result of interest charges on the new syndicated revolving credit facility. The Company drew down $179.8 million on the credit facility at June 29, 2010, for the purchase of Iteration and has since made repayments to bring the debt balance down to $167.8 million resulting in a higher debt balance through the period and therefore higher interest charges.

Twelve Months

During 2010, interest and financing charges increased $11.6 million and included the fair value of the share purchase warrants associated with the bridge facility of $2.6 million, commitment fees of $2.2 million and financial advising fees of $1.5 million. During the year, the Company entered into a bridge facility with its major shareholder which had interest being charged at a rate of 15% per annum. The facility was only outstanding for 41 days before it was fully repaid. A credit facility was established with Société Générale in the first quarter of 2010 and had $4.6 million of interest costs for the twelve months. The average debt for the year was $115.0 million resulting in an average interest rate of 4.23%.

7.5. Depletion, Depreciation and Accretion ("DD&A")

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2010**	2009	**2010**	2009
Canada	**$ 29,151**	$ -	**$ 73,653**	$ -
Tunisia	**3,473**	1,459	**5,909**	1,828
Corporate	**-**	11	**21**	40
Total	**32,624**	1,470	**79,583**	1,868
Per sales *(boe)*	**$ 22.26**	$ 171.81	**$ 22.16**	$ 75.27

Fourth Quarter

During 2010, DD&A increased $31.2 million when compared with the same period in 2009 with the acquisition of producing assets in Canada and Tunisia in 2010. The Company has included a total of $63.2 million of future development costs in the costs to be depleted and excluded costs of $88.7 million for projects still under evaluation.

Twelve Months

During 2010, DD&A increased $77.7 million primarily as a result of the depletion charge associated with the acquisition of Canadian assets, the increase in working interest of the Sud Remada property and the acquisition of the Adam property in Tunisia.

7.6. Tax Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2010**	2009	**2010**	2009
Current tax expense	**$ 2,923**	$ -	**$ 4,245**	$ -
Future tax expense	**(3,896)**	-	**(10,313)**	-
Total	**$ (973)**	$ -	**$ (6,068)**	$ -

Current tax expense of $4.2 million is payable in Tunisia on the Adam concession producing assets. The future tax expense is a result of lower resource pool balances available for tax on the Iteration assets when compared to net book values, which is partially offset by higher resource and other pools associated with the remainder of the Canadian assets and operations.

7.7. Net Loss

	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Net loss - continuing operations	**$ (12,893)**	$ (1,332)	**$ (31,952)**	$ (5,999)
Basic and diluted per share	**(0.06)**	(0.02)	**(0.20)**	(0.08)
Net income (loss) - discontinued operations	**-**	(14,995)	**(13,540)**	(13,618)
Basic and diluted per share	**-**	(0.20)	**(0.08)**	(0.19)
Net loss	**(12,893)**	(16,327)	**(45,491)**	(19,617)
Basic and diluted per share	**(0.06)**	(0.22)	**(0.28)**	(0.27)
Comprehensive loss	**(12,893)**	(8,476)	**(66,676)**	(23,566)
Basic and diluted per share	**(0.06)**	(0.11)	**(0.41)**	(0.32)
Weighted average shares outstanding *(thousands)*	**214,188**	73,839	**162,003**	73,681

Fourth Quarter

A net loss of $12.9 million for the fourth quarter is higher than the net loss in the comparable period in 2009 of $1.3 million.

Twelve Months

During 2010, the net loss increased $25.9 million over the same period in 2009. Primarily the increase resulted from:

- $44.6 million increase in production expenses from the acquired Canadian assets and increase in Tunisia assets;
- $77.7 million increase in depletion and amortization;
- $17.4 million increase in general administrative costs;
- $11.6 million increase in interest and financing charges; and
- $4.2 million increase in current taxes.

Partially offset by:

- $112.9 million increase in revenue net of production expenses from acquired Canadian and Tunisian assets;
- $5.2 million in gathering and processing income; and
- $10.3 million recovery in future income taxes.

8. Quarterly Information

Summarized information by quarter for the two years ended December 31, 2010, appears below:

($ thousands, except per unit amounts) [4]	**Dec. 31 2010**	Sept. 30 2010	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009
Production revenue net of royalties	**$ 47,227**	$ 44,869	$ 17,321	$ 9,554	$ 3,718	$ 2,659	$ 5,217	$ 9,275
Cash flow [1]	**22,576**	30,643	(190)	2,386	2,856	3,139	8,010	5,517
Per share								
Basic *($)*	**0.11**	0.14	-	0.02	0.04	0.04	0.11	0.07
Diluted *($)*	**0.11**	0.14	-	0.02	0.04	0.04	0.10	0.07
Net income (loss)	**(12,893)**	(6,125)	(14,570)	(11,902)	(16,327)	(2,303)	1,987	(2,975)
Per share								
Basic *($)*	**(0.06)**	(0.03)	(0.12)	(0.13)	(0.23)	(0.03)	0.03	(0.04)
Diluted *($)*	**(0.06)**	(0.03)	(0.12)	(0.13)	(0.23)	(0.03)	0.03	(0.04)
Average daily production *(boe)*	**15,354**	16,089	5,562	3,196	1,424	1,173	1,905	2,174
Capital expenditures [2] [3]	**$ 25,454**	$ 32,260	$ 261,838	$ 207,055	$ 4,990	$ 2,141	$ 4,892	$ 6,394

[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.*
[3] *March and June 2010 include acquisitions of Canadian and Tunisian producing assets and assets from the corporate acquisition of Iteration.*
[4] *Includes discontinued operations for periods September 2008 - March 2010.*

Factors That Have Caused Variations over the Quarters

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

With the Company's 100% interest in Silverstone being fully included in the results for the first quarter of 2009, that period's net production revenue was the highest presented until the acquisitions in Canada in 2010. Natural gas prices have slumped in the intervening period resulting in lower net production revenue. Production in Tunisia commenced in the second quarter of 2009 resulting in an increase to both revenue and cash flows. Production from the North Sea, UK in the third quarter of 2009, was curtailed for approximately 30 days to allow a third party the time needed to replace a pipeline. A significant increase in the depletion charge in the fourth quarter of 2009 resulted in that period's large net loss. The Company's proved reserves relating to the North Sea, UK business were independently evaluated and revised downward in the fourth quarter of 2009, resulting in a material charge for the period when compared to the prior periods presented. The Company completed the acquisition of Canadian and Tunisian producing assets in March 2010, increasing production, revenues and cash flow. The Company disposed of its interest in Silverstone in the first half of 2010 and presented its operations as discontinued for financial reporting. Chinook's capital expenditures throughout all of 2010 increased significantly due to the various property and corporate acquisitions that were completed. These acquisitions also contributed to the substantial increase in production revenue and overall production volumes during the second half of 2010.

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.

9. Outstanding Share Data

Authorized:

- Unlimited number of common shares
- Unlimited number of first preferred shares

Details of share capital, options and warrants outstanding at December 31 are as follows:

	2010	2009
Common shares outstanding	**214,187,681**	75,224,490
Share options	**12,136,394**	4,089,800
Warrants	**1,279,000**	-
Fully diluted common shares	**227,603,075**	79,314,290
Weighted average common shares - basic and diluted	**162,002,937**	73,680,985

At December 31, 2010, the Company had 214.2 million shares, 12.1 million options and 1.3 million warrants outstanding. One shareholder, the AIMCo which manages certain pension funds on behalf of the province of Alberta, held approximately 38% of the issued and outstanding shares of the Company at December 31, 2010. As at March 30, 2011, there were 214.2 million shares outstanding, 12.0 million options outstanding and 1.3 million share purchase warrants outstanding.

10. Contractual Obligations and Commitments

Other than those commitments associated with office premises and debt repayment as disclosed in section 3 of this MD&A, the Company does not have any other contractual obligations.

The Company has legal and tax claims that have arisen out of the normal course of business. The outcome of such claims is not determinable.

11. 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 are subject to a myriad of factors 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 U.S. 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; and
- Price controls and varying forms of fiscal regimes or changes thereto.

In late 2010 and early 2011, Tunisia experienced a period of political unrest and civil disobedience of increasing intensity leading 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 and Libya has been the subject of international sanctions. As reported in the press, Libya is currently experiencing 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. The Libyan situation has created a humanitarian emergency on the southeast Tunisian border with the flood of refugees into Tunisia having the potential to further de-stabilize the country. As at the date of this MD&A, Chinook's Tunis office and Sud Remada 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 we consider possible in the current situation. Chinook assesses the situation daily in the context of what its plans are 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 Sud Remada, it is possible that the security situation will deteriorate to the point that Chinook deems it appropriate to suspend operations.

Chinook is also exposed to financing 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.

Being part of the oil and natural gas industry and operating in a foreign country, the Company is subject to various governmental regulations which change from time to time and which are quite extensive. The Company is committed to operating as a good corporate citizen in a responsible manner. The Company is committed to a continual program of exploration and development, guided by a very experienced and qualified team.

Additional risk factors which may affect Chinook are outlined in the annual information form of Chinook for the year ended December 31, 2010, available on SEDAR at www.sedar.com.

12. Application of Critical Accounting Policies and Estimates

The Company’s financial statements were prepared in accordance with Canadian GAAP. A summary of the significant accounting policies can be found in Note 2 of the annual consolidated financial statements. 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 asset retirement obligations, 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 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 the ceiling test 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 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 calculated ceiling, 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 Asset Retirement Obligation

The Company records a liability for the fair value of its legal obligation associated with the abandonment and reclamation of its net ownership in wells and facilities in the period in which the obligation arises, normally when the asset is purchased or developed. Estimations are required regarding the cash flows required for the abandonment and reclamation, the timing of such cash flows, changes in environmental regulations and the discount rate used to calculate the present value of the cash flow.

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.

13. Transition to International Financial Reporting Standards

On February 13, 2008, the Canadian Accounting Standards Board confirmed that the use of International Financial Reporting Standards ("IFRS") will be adopted in full, and without modification, in 2011 for publicly accountable profit-oriented enterprises. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Chinook for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

IFRS will replace current Canadian GAAP for those enterprises. Although IFRS is principles-based and uses a conceptual framework similar to Canadian GAAP, there are significant differences and choices in accounting policies as well as increased disclosure requirements under IFRS. As a result, the transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations. The Company will adopt IFRS, which will be effective for interim and annual periods commencing January 1, 2011, including the preparation and reporting of one year of comparative figures.

The Company created a high-level plan to execute and complete this transition project that included the completion of a diagnostic assessment comparing significant differences between Canadian GAAP and IFRS. The analysis has been reviewed by the Company's external auditors for consistency in the interpretation of the standards. The Audit Committee has approved the IFRS accounting policy sections presented by management to date and disclosed herein. The project is being managed by an in-house team of accounting professionals, along with external advisors, who have engaged in IFRS educational programs and continue to develop the Company's adoption to IFRS. The assessment of the impact was categorized into significant, moderate, or low priority items with significant priority items including property, plant and equipment, foreign operations and the recognition of foreign exchange provisions, asset retirement obligations and income taxes. IFRS in-depth reviews have been concentrated on cash generating units, options available under IFRS for modified full cost accounting, decommissioning liabilities, share-based compensation and a preliminary analysis of the impact on the Company's data gathering and reporting systems. The Company is currently in the final phase of its project. This phase included implementing the required changes necessary for IFRS compliance. The focus of this phase is the finalization of IFRS conversion impacts, approval and implementation of accounting and tax policies, disclosures, implementation and testing of new processes, systems and controls, execution of training programs, preparation of opening IFRS balances, conversion of 2010 GAAP financial statements to IFRS and preparation of a comparative January 1, 2010, opening balance sheet.

Adoption of International Financial Reporting Standards

Opening Balance Sheet

The Company has completed the drafting of its opening balance sheet at January 1, 2010, including preliminary review by the Company's auditors.

The following are IFRS 1 exemptions that Chinook will elect on transition date:

Property, Plant and Equipment ("PP&E")

A Company has the option to elect fair value at the date of transition as the deemed cost for its PP&E or to use a revalued amount according to its previous GAAP if the revaluation, at the date of revaluation, is comparable to fair value or depreciated cost in accordance with IFRS. On July 23, 2009, the International Accounting Standards Board published amendments to IFRS 1 which will allow an election to measure oil and natural gas assets at the date of transition to IFRS at the amount determined under Canadian GAAP. The standard allows a Company to allocate its PP&E asset base to the Company's cash generating units based on reserve volumes or values. The Company has elected to apply this optional exemption under IFRS 1 for its opening balance sheet at January 1, 2010. The Company has allocated the historical full cost pool under Canadian GAAP to cash-generating units based on proved plus probable reserve values.

Asset Retirement Obligation

Under IFRS, either cash flow or the interest rate should be risked in calculating the asset retirement obligation (called decommissioning liability under IFRS). This differs from Canadian GAAP, which requires a credit-adjusted risk-free interest rate to be used to discount future cash flows. The Company will re-measure its asset retirement obligation by applying a lower risk-free interest rate resulting in an upward revision to asset retirement obligation.

Business Combinations

An exemption under IFRS 1 provides the entity with relief on the restatement of business combinations prior to the transition date. Under IFRS 3 "Business Combinations", the determination of the fair value of share consideration differs from the determination under current Canadian accounting standards. Any difference in the fair value calculation would have a resulting impact on the carrying amount of net assets acquired, non-controlling interest and any goodwill. The Company has taken the election under IFRS 1, allowing Chinook to be exempt from restating business combinations prior to the transition date to IFRS.

Share-Based Payment

Differences in the accounting for the Company's share option plan have been identified. IFRS 2, "Share-Based Payment", requires the Company to estimate the number of options expected to vest when a grant of equity instruments do not vest immediately. An estimate of the option's life is also required for the estimation of the fair value of the instruments. IFRS 2 does not allow the recognition of the expense on a straight-line basis and requires each installment to be treated as a separate arrangement. Currently, the Company accounts for forfeitures as they occur and considers the estimated life of the options to be consistent with their expiry date. Share-based compensation expense is accounted for using the graded method which is required under IFRS. IFRS 1 provided an elective exemption which the Company has taken, which allows Chinook to apply IFRS 2 to unvested options outstanding on transition date.

The Company elected the following in lieu of full retrospective restatement by availing itself to IFRS 1 exemptions:

- remove the cumulative currency exchange losses of $13.7 million that were in other comprehensive income and increase the deficit accordingly;
- allocate the opening balance of property, plant and equipment to development and production assets and to evaluation and exploration assets based on values; and
- not to restate previous corporate acquisitions or business combinations as the Company had early adopted fair value consideration for business combination accounting under Canadian GAAP.

On first adoption of IFRS, the Company was required to carryout an impairment test of its property, plant and equipment regardless of indications of impairment. The Company did not have any impairment test write downs associated with its petroleum and natural gas properties.

The Company made the following adjustments to the opening balance sheet to comply with IFRS:

- discounted decommissioning liabilities (previously Asset Retirement Obligation) to a risk-free rate from a credit-adjusted risk-free rate. The effect of this was to increase the liability and correspondingly increase the accumulated deficit by $0.1 million;
- restated share-based compensation to reflect graduated vesting as required by IFRS 2 *Share-Based Payment.* The effect of this was to increase contributed surplus and correspondingly increase the accumulated deficit by $1.0 million; and
- income tax effect of the above was $nil.

Policies Adopted

The Company has prepared its preliminary first, second and third quarter comparative 2010 financial statements under IFRS utilizing the various policy choices selected by management.

The areas where Chinook had choices to adopt accounting policies were pursuant to IFRS 6 *Exploration for and Evaluation of Mineral Resources* ("IFRS 6") and IAS 16 *Property, Plant and Equipment* ("IAS 16"). In choosing policies, the Company considered its own circumstances, practicality, and congruence with its business model.

The Company has elected to treat non-producing mineral lands and leases, seismic on owned lands and successful exploration drilling as Exploration and Evaluation assets. Costs of dry and abandoned exploration wells, seismic on non-owned lands, land rentals and carrying costs, and prospecting will be written off as incurred.

Development and Producing costs will be depleted using the "units of production" method based on proved plus probable reserves. The Company will expense the cost of dry and abandoned development wells.

Year Ended December 31, 2010

In 2010, the Company made material transactions that essentially changed the Company from what it was at January 1, 2010. The Company became a reporting issuer in certain of the provinces of Canada on July 6, 2010, with the acquisition of Iteration. Prior to that, the Company sold its indirect wholly-owned UK subsidiary that comprised $316 million of the $362 million in PP&E on the January 1, 2010, balance sheet. In 2010, the Company purchased significant assets in Canada ($175 million from Provident Energy Resources Inc., $44.6 million from another producer, and $619 million being the Iteration purchase). The Company also purchased assets in Tunisia totaling USD $22 million. The Company accounted for these pursuant to section 1582 of the CICA Handbook and as such will not need to restate these purchases with the adoption of IFRS.

The Company has reviewed first time adoption exemptions and elections available upon initial transition that provide relief from retrospective application in the January 1, 2010, opening balance sheet.

The Company will continue to monitor any changes in the adoption of IFRS, it will implement those policies determined to be the most appropriate for the Company and will update its plan as necessary.

Below, Chinook has identified key differences that will impact the financial statements. The list and comments below should not be regarded as a complete list of changes that will result from transitioning and adopting IRFS.

- Currently the Company capitalizes and depletes pre-exploration costs within the country cost centre. The Company expects that some pre-licence exploration costs, such as seismic costs where the Company has no petroleum and natural gas rights, will be expensed under IFRS.
- Exploration and Evaluation ("E&E") expenditures – On transition to IFRS, Chinook will reclassify all E&E expenditures that are currently included in the property and equipment ("PP&E") balance on the consolidated balance sheet. This will consist of the book value of undeveloped land and unevaluated seismic data that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist. When technical feasibility and commercial viability are determined, the costs will be transferred to PP&E. E&E costs will be expensed if technical feasibility and commercial viability cannot be established;
- Depletion expense – On transition to IFRS, Chinook has the option to base the depletion calculation on either proved reserves or proved plus probable reserves. Chinook has chosen to deplete its developing and producing assets on a unit-of-production basis using proved plus probable reserves;
- Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed at the cash generating unit level using either total proved or proved plus probable reserves. Canadian GAAP allows an impairment test to be performed on a country cost centre basis;
- Decommissioning Liabilities – A major difference between current Canadian standards and IFRS appears to be the discount rate used to measure the asset retirement obligation. Under current Canadian standards, a credit adjusted risk-free rate is used in calculating the provision. Under IFRS, a risk-free rate should be used when the expected cash flows are risked. Within

the industry, there has been a debate on whether there should be a risk component applied to conventional property estimated cash out flows used in determining the provision. The Company has decided to use the lower risk-free rate; and

- Income taxes – Current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (i) an item that has been recognized directly in equity, whether in the same or a different period, (ii) a business combination or (iii) a share-based payment transaction. If a deferred tax asset or liability is re-measured subsequent to initial recognition, the impact of re-measurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the re-measurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing". Canadian GAAP prohibits backwards tracing expect on business combinations; and
- Increased disclosure requirements are also necessary for IFRS. As each significant item is analyzed, disclosure requirements will be documented to ensure required information is available.

Information Technology and Data Systems

Chinook has performed a preliminary assessment of the implications of IFRS on its information technology and data systems. The Company's current data gathering and accounting system is capable of obtaining and recording data at a level of detail required for IFRS. The Company has identified transactions relating to its PP&E in relation to requirements under IFRS to have the most impact on its information technology and data systems. In order to comply with some of the requirements under IFRS, the Company will need to be able to record assets at the E&E and Developing and Producing ("D&P") categories, have the ability to transfer expenditures from the E&E phase to the D&P phase and record DD&A at the cash generating unit level or lower.

Chinook is determining which additional changes to internal controls over financial reporting will be required to deal with the changes in accounting policies. This will be ongoing to ensure all changes in accounting policies include appropriate additional controls and procedures for future IFRS reporting requirements.

Chinook will continue to monitor standards development as issued by the International Accounting Standards Board and the Canadian Accounting Standards Board, as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of Chinook's adoption of IFRS.

14. Disclosure Controls and Procedures

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 periods 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 period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year-end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year-end of the Company for the foregoing purposes.

15. Internal Controls over Financial Reporting

The Company's CEO and CFO are responsible for designing disclosure controls and internal controls over financial reporting as defined in National Instrument 52-109 Certification of Disclosures in Issuer's Annual and Interim filings. As of December 31, 2010, the CEO and CFO have designed, or caused to be designed under their supervision, internal control 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 Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at December 31, 2010 and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2010, and ended on December 31, 2010, that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during the period 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.

16. Other Information

16.1. 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 oil and natural gas reserves; the value of Chinook's undeveloped land holdings; the volume of Chinook's oil and natural gas production; 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: Chinook's ability to continue to operate in Tunisia with limited logistical issues; Chinook's ability to obtain equity and debt financing on satisfactory terms; oil and natural gas prices; well production rates and reserve volumes; Chinook's ability to add commercially viable and economic production and reserves through exploration and development activities; 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: 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 problems and other difficulties in 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.

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 the general economic conditions.

16.2. Non-GAAP Measures

Throughout this MD&A, the Company uses terms "cash flow", "cash flow per share", "operating netback and "reserve life index". These terms do not have any standardized meaning as prescribed by Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures presented by other companies.

Cash Flow

Cash flow is calculated based on cash flow from continuing operating activities before changes in non-cash working capital. Cash flow per share is calculated based on cash flow from continuing operating activities before changes in non-cash working capital from continuing operations. Management believes that cash flow is a supplemental measure and utilizes it as a key measure to assess the ability of the Company to finance operating activities, 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 GAAP 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 December 31		Year ended December 31	
($ thousands)	**2010**	2009	**2010**	2009
Cash flow from continuing operating activities	**$ 18,469**	$ (776)	**$ 56,985**	$ (2,094)
Change in non-cash working capital from continuing operations	**4,106**	8	**(5,256)**	858
Cash flow	**$ 22,576**	$ (784)	**$ 51,729**	$ (1,236)

Operating Netback

Operating netback is calculated as production revenue less royalties, production expenses and cash G&A. 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 better measure performance against prior periods on a comparable basis.

Reserve Life Index

The term reserve life index ("RLI") is not a recognized measure under GAAP. Management believes that this measure is a useful supplemental measure of the length of time the reserves would be produced over at the rate used in the calculation. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with GAAP as a measure of performance. Chinook's method of calculating this measure may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

16.3. Related Party Transactions

The Company utilizes the services of a law firm in which the Corporate Secretary and a director of the Company are partners. During 2010, the Company incurred $1.6 million (2009 - $0.2 million) on legal services obtained from the firm. Legal services provided relate to advice and counsel primarily in the areas of general legal, securities legislation, corporate governance matters, corporate acquisitions, and banking and financing offerings. These services were billed at normal commercial terms consistent with those charged to third parties. The Company expects to continue using the services of this law firm throughout the remainder of 2011.

The Company provides certain services to nominees of AIMCo, a major shareholder of the Company, pursuant to an administrative services and cost sharing agreement and manages the working interests of nominees of AIMCo in a limited partnership. The calculated reimbursement since the inception of the agreement, July 1, 2010, in the amount of $2.3 million has been included in accounts receivable and other. At December 31, 2010, $9.7 million remained in accounts payable and $3.6 million remained in accounts receivable related to the ongoing operations of jointly-held producing and non-producing oil and natural gas properties.

16.4. Off Balance Sheet Arrangements

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