valeura energy inc.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2011 and 2010

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Valeura Energy Inc. ("Valeura" or the "Company") is dated as of August 24, 2011 and should be read in conjunction with Valeura's unaudited consolidated financial statements and related notes for the periods ended June 30, 2011 and 2010. Additional information relating to Valeura is available under Valeura's profile on www.sedar.com, including Valeura's annual information form for the year ended December 31, 2010.

Basis of Presentation

The interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting of the International Financial Reporting Standards ("IFRS"). IFRS 1 – First-time Adoption of International Financial Reporting Standards ("IFRS 1") has been applied to these interim consolidated financial statements.

These interim consolidated financial statements follow the same accounting policies and method of computation as shown in note 3 of the Company's interim consolidated financial statements for the three months ended March 31, 2011. These are the accounting policies the Company expects to adopt in its annual consolidated financial statements for the year ended December 31, 2011, with the exception of certain disclosures that are normally required to be included in annual consolidated financial statements which have been condensed or omitted. The reporting and measurement currency is the Canadian dollar, unless otherwise indicated.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in note 17 of the consolidated financial statements. The note includes reconciliations of equity and net loss for comparative periods from former Canadian GAAP ("previous GAAP") to IFRS.

The discussion and analysis of oil and natural gas production is presented on a working-interest, before royalty basis. For the purpose of calculating unit of production information, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe as a unit of measure may be misleading, particularly if used in isolation.

The Company makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, reserves, environmental and asset retirement obligations and income taxes at each financial reporting period. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Readers should be aware that historical results are not necessarily indicative of future performance.

Comparative Amounts

Comparative amounts in the MD&A and consolidated financial statements for periods prior to the April 9, 2010 closing date of the PanWestern Energy Inc. ("PanWestern") and Northern Hunter Energy Inc. ("Northern Hunter") business combination are the stand alone accounts for Northern Hunter, a private company until completion of the business combination.

Special Note Regarding Non-IFRS Measures – This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "operating netback" (petroleum and natural gas sales less royalties, production expenses and transportation costs) and "funds flow from operations" (net loss for the period adjusted for non-cash items) are not IFRS measures and do not have standardized meanings prescribed by IFRS. The closest IFRS measure to operating netback and funds flow from operations is net loss – see the reconciliation of these non-IFRS financial measures to net loss on page 7 under "Results of Operations".

Forward-looking Statements – Certain information included in this MD&A constitutes forward-looking information under applicable securities legislation. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this MD&A includes, but is not limited to, information with respect to: the Company's growth strategy, operational decisions and the timing thereof; development and exploration plans for the Company's Turkish operations, including any additional expenditures and timing associated with the Phase II earning program under the AME-GYP farm-in and the extent of the Company's earning on the farm-in lands, which is currently under review; the outcome of the Company's application to the General Directorate of Petroleum Affairs of the Republic of Turkey ("GDPA") for an exploration license on one of the cancelled Rubai licenses and an extension on a Karakilise license and the timing associated therewith; the ability of the Company to obtain GDPA approval for the transfer of working interests in leases and licenses to Valeura and the timing thereof; the drilling plans for the Altinakar-1 well and the timing thereof; the plan to consolidate the Company's common shares on a 10:1 basis and to graduate the Company's listing to the TSX; the expected increase in the Company's bank loan capacity; and, future production levels. Forward-looking information is based on a number of factors and assumptions which have been used to develop such information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking information is reasonable, undue reliance should not be placed on forward-looking information because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this MD&A, assumptions have been made regarding and are implicit in, among other things: the ability of the Company to execute its strategy and close on acquisitions; field production rates and decline rates; the ability of the Company to secure adequate product transportation; the impact of increasing competition in or near the Company's plays; the timely receipt of any required regulatory approvals, including stock exchange approvals, both domestically and internationally; continued operations of and approvals forthcoming from the GDPA in a manner consistent with past conduct; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner to develop its business; the Company's ability to operate the properties in a safe, efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion; future oil and natural gas prices; currency, exchange and interest rates; the state of the capital markets; the regulatory framework regarding royalties, taxes and environmental matters; the ability of the Company to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in foreign countries; and the ability of the Company to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking information. The material risk factors affecting the Company and its business are similar to those of other companies engaged in the business of exploring for and producing oil and gas, both domestically and in foreign countries. See the "Business Risks and Uncertainties" section of this MD&A for a further description of the risks facing the Company.

The forward-looking information contained in this MD&A is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward looking information contained in this MD&A is expressly qualified by this cautionary statement**.**

Highlights and Selected Financial Information

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Petroleum and natural gas sales	**$ 2,707,193**	$ 892,878	**$ 3,269,325**	$ 1,754,225
Net loss	**(4,359,006)**	(3,194,474)	**(8,621,015)**	(4,901,585)
Per share, basic and diluted	**(0.02)**	(0.02)	**(0.04)**	(0.04)
Funds flow from operations[1]	**(1,622,240)**	(885,673)	**(3,546,565)**	(1,233,190)
Per share, basic and diluted	**$ (0.01)**	$ (0.01)	**$ (0.02)**	$ (0.01)
Production volumes				
Crude oil and NGL's (bbl/d)	**57**	97	**55**	87
Natural gas (Mcf/d)	**3,810**	994	**2,219**	980
Total (boe /d)	**692**	263	**425**	250
Sales prices				
Crude oil (per bbl)	**$ 82.20**	$ 66.44	**$ 76.35**	$ 68.46
Natural gas liquids (per bbl)	**48.97**	45.84	**51.50**	45.52
Natural gas (per Mcf)	**6.68**	3.83	**6.36**	4.32
Total (per boe)	**43.02**	37.35	**42.50**	38.64
Capital expenditures	**$ 55,650,606**	$ 449,670	**59,848,568**	843,847
Net working capital surplus[2]			**37,101,075**	27,436,979
Cash and cash equivalents			**32,504,845**	28,547,522
Credit facility			**$ -**	$ -
Weighted average shares outstanding (basic and diluted)[3]	**262,835,979**	166,592,079	**230,933,786**	117,213,281

1. Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning expenditures and net changes in non-cash working capital
2. Net working capital is calculated as cash, working capital and demand credit facility borrowings
3. The average number of common shares outstanding was not increased for outstanding stock options and performance warrants as the effect would be anti-dilutive.

Outstanding Share Data

As at June 30, 2011	
Common shares	464,061,475
Warrants	132,692,175
Stock options	21,138,615
Performance warrants	27,967,500
Diluted	645,859,765

The Company

Valeura Energy Inc. and its subsidiaries are currently engaged in the exploration, development and production of petroleum and natural gas in Turkey and Western Canada. The Company is continuing to pursue a strategy to expand internationally in Turkey and other selected countries in the region. Valeura’s shares are traded on the TSX Venture Exchange under the trading symbol VLE. In July 2011, the Company filed an application with the TSX to graduate to a TSX listing. The Company has approximately 464 million shares outstanding and plans to consolidate its shares, subject to TSX approval of the graduation to a TSX listing.

Valeura evolved from two predecessor companies, PanWestern, a public company that was listed on the TSX Venture Exchange, and Northern Hunter, a private oil and gas company, both of which operated in Canada. On April 9, 2010, PanWestern and Northern Hunter completed a Plan of Arrangement (the “Arrangement”) under the Business Corporations Act (Alberta) whereby PanWestern acquired all of the assets and liabilities of Northern Hunter. Upon completion of the Arrangement, Northern Hunter shareholders held approximately 57.4% of the issued and outstanding shares of PanWestern, prior to considering the effect of any equity financings. As a result, the Arrangement is accounted for as a purchase of PanWestern by Northern Hunter, or a reverse take-over, using the purchase method based on the fair values of assets and liabilities of PanWestern (see note 5). As part of the Arrangement, the Board of Directors of PanWestern was reconstituted with members from Northern Hunter and the management team became that of Northern Hunter. Subsequent to completion of the Arrangement, PanWestern changed its name to Valeura as approved at PanWestern's annual and special meeting of shareholders on June 29, 2010.

Valeura adopted a strategy to achieve early international growth through opportunistic acquisitions of producing assets with exploitation and exploration upside in selected countries in regions of interest which included the Middle East and North Africa region, the Mediterranean Basin and South America. The Company completed its first international transaction in Turkey, one of the targeted countries, on September 1, 2010 and had executed four other significant transactions in Turkey as at June 30, 2011. The Company now holds interest in approximately 2.6 million gross acres (1.0 million net) in Turkey, assuming all farm-in interests are earned. The Company owns a 40 percent interest in an established shallow gas production and marketing business in the Thrace Basin of Turkey and holds a large acreage position in the Thrace Basin with exposure to a potentially significant tight gas resource play below the existing shallow gas production.

Turkish Operations

AME-GYP Farm-in

Valeura's first transaction in Turkey was a two-phase farm-in on lands held by Aladdin Middle East Ltd. ("AME") and Guney Yildizi Petrol Uretim Sondaj, Muteahhitlik ve Ticaret A.S. ("GYP") for a minimum consideration of US$8.8 million (Phase I) and a maximum consideration of US$17.6 million (Phase I + Phase II) by the end of 2011. The lands are in the Anatolian Basin in southeast Turkey, which are prospective for light and heavy oil development, exploitation and exploration. The lands included a production lease on the Kahta heavy oil field, three exploration licenses in the Karakilise area and five exploration licenses in the Rubai area. Subsequent to the execution of the farm-in agreement, one exploration license was relinquished in the Karakilise area and a second has been continued for a further three years following a successful recompletion of an existing well. An application has been submitted to the General Directorate of Petroleum Affairs of the Republic of Turkey (“GDPA”) to continue the third exploration license at Karakilise for a further three years following a new discovery drilled by Valeura under the earning program. The application was published in Turkey’s Official Gazette on June 26, 2011, and at this time the outcome and timing of a GDPA decision is uncertain. At Rubai, all five licenses expired due to the failure to meet district drilling requirements. Valeura re-applied for one of the expired Rubai exploration licenses on May 12, 2011. Valeura is one of five companies that submitted conforming bids for this license as published in Turkey’s Official Gazette. The outcome and timing of this application is also uncertain.

As of June 30, 2011, US$8.45 million was recorded as capital under the farm-in, with an additional US$750,000 advanced to AME-GYP. A decision on further expenditures under the optional Phase II program is currently under review.

Edirne Asset Acquisition

The Company closed its purchase of natural gas assets in the Thrace Basin from Edirne Enerji Petrol Arama Üretim Ve Ticaret Limited Şirketi ("Edirne") on March 24, 2011 for a total cash payment of approximately $1.9 million.

The Edirne license covers an area of 100,080 gross acres (35,028 net acres) in the Thrace Basin. Valeura acquired a 35 percent working interest in the lands and producing assets associated with the Edirne license. Opportunities exist on the Edirne license to carry out well workovers, compression and additional drilling to mitigate natural declines. There is additional upside in prospective deeper conventional and unconventional tight gas plays. The Company will be focusing on determining the potential for these types of plays on the Edirne license in conjunction with the broader assessment of the deep potential on the Company's lands in the Thrace Basin.

Thrace Basin (TBNG-PTI) Asset Acquisition

The Company closed its second acquisition of producing natural gas assets and lands in the Thrace Basin of northwest Turkey and interests in exploration lands in the Southeast Anatolian Basin (Gaziantep area) of southeast Turkey owned by Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") and Pinnacle Turkey Inc. ("PTI") on June 8, 2011 for $53.7 million (after adjustments for the period from the effective date of October 1, 2010 to June 8, 2011). This acquisition closed contemporaneously with acquisitions made by affiliates of TransAtlantic Petroleum Ltd. ("TransAtlantic") from the same vendor.

This acquisition provides immediate cash flow to the Company from sales of shallow gas production in the Thrace Basin, interests in 1,832,894 gross acres of land (588,719 net), and exposure to a potentially significant unconventional tight gas opportunity in the Thrace Basin.

The lands located in the Thrace Basin include four production leases and 10 exploration licences, of which two licences are entirely on land, three licences have a portion in the shallow waters (up to 200 meter water depth) of the Sea of Marmara and five licenses are in the deeper waters (200 to 1,200 meter water depth). Valeura has interests in 507,851 gross acres (203,140 net) in the onshore areas and 715,217 gross acres (227,024 net) in the offshore areas.

Natural gas is currently produced in the Thrace Basin from approximately 169 wells, all located onshore, that are completed primarily in stacked sands in the Danismen and Osmancik formations at relatively shallow depths of 500 to 1,500 meters. The gas is processed and compressed in TBNG facilities and is distributed on TBNG's pipeline network directly to more than 80 commercial and end-user customers. TransAtlantic has taken over responsibilities for the marketing arrangements on behalf of the parties.

Opportunities exist on the Thrace Basin lands to continue to pursue exploration and development drilling, well workovers and wellhead compression to mitigate natural declines in existing production from conventional shallow gas reservoirs. In 2010, for example, 50 exploration and development wells were drilled by TBNG in the Thrace Basin. Approximately 3,500 km of legacy 2D seismic is available on the onshore lands in the Thrace Basin and it is expected that additional 2D and 3D seismic will be acquired to support the Company`s anticipated exploration and development drilling program.

Valeura believes there is upside potential associated with applying modern technology to exploit deeper tight gas sand and shales in the Mezardere, Ceylan, and Hamitabat formations at depths to the top of these formations from 1,000 to 3,500 meters. Selective deep drilling in the past indicates the presence of relatively low porosity (3 to 15%), stacked sandstone reservoirs in these formations that are gas-charged.

The lands located in the Gaziantep area of the Southeast Anatolian Basin include five exploration licenses covering an area of 609,826 gross acres (158,555 net).

Thrace Basin Farm-ins

On May 4, 2011, the Company completed a farm-in to earn a 100 percent working interest on License 4201 (Marhat farm-in) in the Thrace Basin. The license requires a commitment to drill two wells. The Company expects to drill the first well in 2012. The estimated commitment of $3.0 million is anticipated to be spent in 2012.

On June 13, 2011, the Company completed a farm-in to earn a 50 percent working interest on Licenses 4094 and 4532 (TransAtlantic farm-in) in the Thrace Basin. The combined licenses require the commitment to drill two wells and spend approximately US$3.0 million on seismic. The Company plans to drill the first well and initiate the seismic program in 2011. The estimated committed expenditure is anticipated to be $2.5 million in 2011 with a further $4.5 million in 2012.

Financing

Upon closing of the TBNG-PTI asset acquisition, the Company received funds out of escrow from its February 2011 private placement of subscription receipts. Total gross proceeds were $86.25 million. Valeura issued a total of 265,384,350 subscription receipts at a price of $0.325 per subscription receipt. The underwriters received a fee equal to 5% of the gross proceeds raised, of which $1,509,373 was paid at closing on February 28, 2011 and the remainder totalling $2,803,122 was paid upon satisfaction of the escrow release conditions. Net proceeds from the private placement financing after share issuance costs were $81,066,022.

Each subscription receipt represented the right to automatically receive one common share and one-half of one common share purchase warrant of the Company and the subscription receipts were converted into the underlying common shares and warrants on June 8, 2011 concurrently with the release of funds from escrow and the closing of the TBNG-PTI asset acquisition. Each full warrant entitles the holder to acquire one common share at a price of $0.55 per common share for a period of 60 months from the closing of the offering (which occurred on February 28, 2011). The Company will have the right to accelerate the expiry of the warrants to 30 days from the date of notice if the 20 day volume weighted average price of the Company's common shares on the TSX Venture Exchange is equal to or greater than $1.10 per common share. The warrants have been valued at $5,971,148 or $0.045 per warrant.

Outlook

Operations

The Corporation's primary focus at this time is to "bed-down" the assets acquired in the TBNG-PTI transaction which is the largest of five transactions executed in Turkey since September 2010 and the Corporation's largest source of cash flow.

With respect to the shallow gas business in the Thrace Basin, work is focused on replenishing the inventory of well recompletions and workovers on existing wells through an intense effort to look at all producing and suspended wells. These opportunities have the lowest cost and promise the quickest payout. To build the inventory of drillable prospects (both exploration and development) and to improve the drilling success rate, a large 3D seismic program is underway in two high potential areas on the TBNG-PTI lands where significant operations are already in place. The fully interpreted results are not expected until the first quarter of 2012. In the meantime, the Corporation is focused on high-grading the 2011 drilling inventory on the existing 2D seismic.

Unlocking the potential in the deeper tight gas play in the Thrace Basin is a major priority for the Corporation. A deliberate program has been kicked-off to build a comprehensive knowledge base through acquisition of new seismic, more sophisticated well logging, more extensive core analysis work, new G&G studies and a series of "proof-of-concept" field experiments with various frac designs and target tight sand intervals in the Mezardere formation.

Accordingly, the Corporation's work program and budget for 2011 has three main objectives:

- Sustaining the shallow gas business in the Thrace Basin;
- Proving-up the potential of the tight gas play in the Thrace Basin; and
- Fulfilling exploration-focused work programs on high potential farm-in acreage in the Thrace Basin (gas targets) and in the Anatolian Basin (oil targets).

The Corporation has modified its outlook for capital expenditures in 2011 to approximately $20 million compared to earlier guidance of $30 to 35 million based on the results of partner budget meetings in Turkey in late June. This change relates primarily to deferral of some discretionary exploration expenditures. The revised budget outlook excludes any capital invested on the TBNG-PTI and Edirne lands prior to the closing date of these acquisitions, which amounts were reflected in purchase price adjustments. The budgeted funds are essentially all directed to Turkey and include estimates of: $11.7 million for up to 19 drill wells (gross), of which 6 are shallow gas wells and 7 are deeper Mezardere tests (drill and frac) on the TBNG-PTI lands; $2.6 million for up to 50 workovers and 8 fracs (gross) on existing wells in the Thrace Basin; and, $5.7 million for up to 463 square km of 3D seismic and 100 km of 2D seismic in the Thrace Basin.

The Corporation has essentially completed Phase I of the AME-GYP farm-in and is in discussion with AME-GYP on next steps, including possible deepening of the Altinakar-1 well to test the Bedinan formation, contingent on the GDPA granting an extension to the term of Licence 2674. Under terms of the farm-in, Valeura must invest a minimum of US$8.8 million in Phase I to earn a 25% working interest in two exploration licences at Karakilise and a production lease at Kahta. The scope of the ultimate investment and earning under the AME-GYP farm-in remain under review for further discussion with AME-GYP.

Subject to TSX approval of the Corporation's application to graduate to a TSX listing, the Corporation plans to consolidate its issued and outstanding common shares on a 10:1 basis at that time.

Business Development

The Corporation is pursuing other farm-in and acquisition opportunities in Turkey. These have the potential to further expand the Corporation's acreage position, particularly in the Thrace Basin.

The Corporation is also pursuing other opportunities in the region, particularly oil-weighted opportunities, to complement its position in Turkey.

Results of Operations

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Petroleum and natural gas sales	**$ 2,707,193**	$ 892,878	**$ 3,269,325**	$ 1,754,225
Royalties	**(293,904)**	(119,195)	**(350,184)**	(192,700)
Production costs	**(841,078)**	(462,700)	**(1,206,512)**	(852,665)
Transportation	**(10,458)**	(23,985)	**(18,027)**	(45,921)
Operating netback[1]	**1,561,753**	286,998	**1,694,602**	662,939
Other income	**141,994**	27,690	**183,924**	27,690
General and administrative	**(1,720,289)**	(823,382)	**(3,208,504)**	(1,115,978)
Transaction costs	**(1,326,425)**	(369,647)	**(1,937,314)**	(756,598)
Financing costs	**-**	(7,332)	**-**	(51,243)
Income tax	**(279,273)**	-	**(279,273)**	-
Funds flow from operations[2]	**(1,622,240)**	(885,673)	**(3,546,565)**	(1,231,190)
Non-cash expenses				
Stock based compensation	**(627,244)**	(1,830,459)	**(1,241,900)**	(2,678,680)
Transaction costs	**-**	(64,410)	-	(64,410)
Foreign exchange gain	**158,667**	-	**44,663**	-
Financing costs	**(10,754)**	(2,674)	**(13,862)**	(5,174)
Exploration expense	**(902,470)**	-	**(2,280,120)**	(95,795)
Depletion and depreciation	**(1,652,325)**	(411,258)	**(1,880,591)**	(743,636)
Deferred tax recovery (expense)	**297,360**	-	**297,360**	(80,700)
Net loss	**$ (4,359,006)**	$ (3,194,474)	**$ (8,621,015)**	$ (4,901,585)

Operating Netbacks (per boe)[3]

Petroleum and natural gas sales	**$ 43.02**	$ 37.35	**$ 42.50**	$ 38.64
Royalties	**(4.67)**	(4.99)	**(4.55)**	(4.24)
Production costs	**(13.36)**	(19.35)	**(15.69)**	(18.79)
Transportation	**(0.17)**	(1.00)	**(0.23)**	(1.01)
Operating netback	**$ 24.82**	$ 12.01	**$ 22.03**	$ 14.60

Petroleum and Natural Gas Production

Daily production				
Crude oil & NGL's(bbl/d)	**57**	97	**55**	87
Natural gas (Mcf/d)	**3,810**	994	**2,219**	980
Total (boe/d)	**692**	263	**425**	250

[1] Non-IFRS measure – see note regarding non-IFRS measures on page 1
[2] Non-IFRS measure – see note regarding non-IFRS measures on page 1
[3] Operating netbacks are calculated using production volumes on a boe basis for each period

Average production volumes increased by 163 percent to 692 boe/d in Q2 2011 from 263 boe/d in Q2 2010. The increase is due to closing of the Edirne asset acquisition in Q1 2011 and the TBNG-PTI asset acquisition in Q2 2011, partially offset by a decline in Canadian production. Average production volumes increased 82 percent to 425 boe/d from 250 boe/d in the first half of 2011, when compared to 2010, for the same reasons.

Pricing Information

	Three months ended		Six months ended	
	June 30, 2011	**June 30, 2010**	**June 30, 2011**	June 30, 2010
Average benchmark prices				
Crude oil – Edmonton Light (per bbl)	**$ 103.07**	$ 75.13	**$ 95.11**	$ 77.59
Natural gas – BOTAS reference (TL)[4]	**13.21**	13.15	**13.21**	13.15
Natural gas – BOTAS reference	**$ 8.18**	$ 8.79	**$ 8.22**	$ 8.93
Valeura's average realized prices				
Crude oil (per bbl)	**$ 88.20**	$ 66.44	**$ 76.35**	$ 68.46
Natural gas liquids (per bbl)	**$ 49.87**	$ 45.84	**$ 51.50**	$ 45.52
Natural gas – Turkey (per Mcf)	**$ 7.05**	$ -	**$ 7.05**	$ -
Natural gas – consolidated (per Mcf)	**$ 6.68**	$ 3.83	**$ 6.36**	$ 4.32

The following table shows the percentage increase in Valeura's realized prices for Q2 2011 and YTD 2011 when compared with Q2 2010 and YTD 2010:

	Q2 2011	**YTD 2011**
Crude oil	24%	12%
Natural gas liquids	7%	13%
Natural gas (consolidated)	74%	47%

Natural gas prices remain much stronger in Turkey when compared with Canada. With more than 90 percent of Valeura's current production coming from natural gas in Turkey, the Company has positioned itself to take advantage of these higher natural gas prices. The recent weakening of the Turkish Lira against the Canadian Dollar will have some downward pressure on realized natural gas prices as contracts in Turkey are linked to a BOTAS posted price in Turkish Lira.

Petroleum and Natural Gas Sales Revenues

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Revenues by product				
Crude oil	**$ 343,083**	$ 457,884	**$ 611,765**	$ 800,419
Natural gas liquids	**47,530**	88,935	**102,015**	187,992
Natural gas	**2,316,580**	346,059	**2,555,545**	765,814
Total revenues	**$ 2,707,193**	$ 892,878	**$ 3,269,325**	$ 1,754,225

Petroleum and natural gas sales revenues for Q2 2011 were 86 percent natural gas and 14 percent oil and natural gas liquids. Petroleum and natural gas sales revenues for the first six months of 2011 were 78 percent natural gas and 22 percent oil and natural gas liquids. Higher sales revenues were the result of a full quarter of Edirne asset production and the closing of the TBNG-PTI asset acquisition on June 8, 2011.

[4] Boru Hatlari ile Petrol Tasima Anonim Sirketi ("BOTAS") owns and operates the national crude oil pipeline grid and the national natural gas pipeline grid in Turkey. BOTAS regularly posts prices and its Industrial Interruptible Tariff benchmark is shown herein as a reference price. See the 2010 Annual Information Form for further discussion.

Royalties

	Three months ended		Six months ended	
	June 30, 2011	June 30,2010	**June 30, 2011**	June 30, 2010
Total	**$ 293,904**	$ 119,195	**$ 350,184**	$ 192,700
Percentage of revenue	**10.9%**	13.3%	**10.7%**	11.0%

Royalties increased in Q2 2011 and for the six months ended June 30, 2011 when compared to Q2 2010 and the six months ended June 30, 2010 primarily due to the addition of production volumes in Turkey. Royalties per boe decreased in Q2 2011 and the six months ended June 30, 2011 when compared to Q2 2010 and the six months ended June 30, 2010 due to Alberta government royalty credit adjustments.

Operating Costs

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Production costs	**$ 841,078**	$ 462,700	**$ 1,206,512**	$ 852,665
Transportation costs	**10,458**	23,985	**18,027**	45,921
Total operating costs	**$ 851,536**	$ 486,685	**$ 1,224,539**	$ 898,586
$ per boe	**13.53**	20.35	**15.92**	19.80

Overall operating costs decreased for the three and six months ended June 30, 2011 when compared to the same periods in 2010 due to the addition of lower cost production from the Thrace Basin assets in Turkey. On a unit cost basis, costs decreased to $13.53/boe in Q2 2011 from $20.35/boe in Q2 2010. The unit cost decrease is the direct result of lower operating costs in Turkey. For the three and six months ended June 30, 2011, operating costs in Turkey were $0.29 per boe and $0.30 per boe respectively.

With over 90 percent of Valeura's current production coming from Turkey, the Company has positioned itself to take advantage of a lower cost operating environment.

General and Administrative Expenses

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
General and administrative	**$ 1,383,723**	$ 827,882	**$ 2,491,504**	$ 1,129,311
Business development	**339,566**	-	**723,250**	-
Total gross general and administrative expenses	**1,723,289**	827,882	**3,214,754**	1,129,311
Recoveries	**(3,000)**	(4,500)	**(6,250)**	(13,333)
Total net general and administrative expenses	**$ 1,720,289**	$ 823,382	**$ 3,208,504**	$ 1,115,978

General and administrative ("G&A") costs increased significantly in Q2 2011 and the six months ended June 30, 2011 when compared to the same periods in 2010 due to the growth in international business activities. The business development component includes third party agent's fees, consulting, software, legal and travel costs. Other G&A costs are higher due to a larger number of employees and consultants and higher office costs related to an increase in personnel. With the closing of the TBNG-PTI asset acquisition in June 2011, the Company is in the process of hiring a number of key full-time employees to replace consultants which typically have a higher cost.

Transaction Costs

In accordance with IFRS 3 – "Business Combinations", acquisition related costs (transaction costs) are recognized separately from the business combination and are included in the statement of loss. Q2 2011 transaction costs were $1,326,425 compared to $434,057 in Q2 2010, and $1,937,314 for the six months ended June 30, 2011 compared to $821,008 for the six months ended June 30, 2010. 2011 transaction costs pertained to the Edirne and TBNG-PTI asset acquisitions, and Marhat and TransAtlantic farm-ins, while 2010 transaction costs pertained to the PanWestern-Northern Hunter business combination.

Financing costs

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Accretion of decommissioning obligations	**$ 10,754**	$ 2,674	**$ 13,862**	$ 5,174
Interest expense	**-**	7,332	**-**	51,243
	$ 10,754	$ 10,006	**$ 13,862**	$ 56,417

Interest expense was $nil for both Q2 2011 and the six months ended June 30, 2011, compared to $7,332 in Q2 2010 and $51,243 for the six months ended June 30, 2010. This is the result of paying down the Company's credit facilities upon completion of the PanWestern-Northern Hunter business combination.

Foreign Exchange

The Company incurred an unrealized foreign exchange gain in Q2 2011 of $158,667 and $44,663 for the six months ended June 30, 2011. The unrealized foreign exchange gain was the result of the translation of accounts denominated in currencies other than the functional currency of Valeura and its subsidiaries. The Company did not have any foreign currency transactions in the first six months of 2010.

Other Income

During the three and six month periods ended June 30, 2011, the Company recorded other income of $141,994 and $183,924, respectively, compared to $27,690 for both the three and six months ended June 30, 2010. Other income is comprised of interest income related to cash on hand.

Income Taxes

During the three and six month periods ended June 30, 2011, the Company recorded $279,273 of current income taxes associated with its Turkish operations. Management anticipates that these taxes will be recovered by year-end 2011 with increased capital spending in the second half of this year. The Company did not record any current income tax expense in 2010.

Funds Flow from Operations

The net outflow of funds from operations for the three and six months ended June 30, 2011 was $1,622,240 and $3,546,565, respectively, compared to $885,673 and $1,233,190, respectively for the same periods in 2010. The increase in net outflow of funds was due to increased general and administrative costs associated with international business development activities, and specifically the Edirne and TBNG-PTI asset acquisitions, partially offset by higher petroleum and natural gas sales revenue.

Non-cash Expenses:

Stock-based Compensation

Stock-based compensation is a non-cash expense associated with the stock options and performance warrants issued to directors, officers, employees and consultants of the Company.

Stock-based compensation expense for the three and six months ended June 30, 2011 was $627,244 and $1,241,900, respectively, compared to $1,830,459 and $2,678,680, respectively for the same periods in 2010. Performance warrants issued in 2010 attracted a higher amount of stock-based compensation expense due to accelerated amortization under IFRS.

Exploration and Evaluation

Exploration and evaluation expenses consist of impairment of the Company's exploration projects. Exploration and evaluation expense for the three and six months ended June 30, 2011 was $902,470 and $2,280,120, respectively, consisting mainly of impairment on the Company's Rubai licenses which expired in May 2011.

Depletion and Depreciation

Depletion and depreciation for the three and six months ended June 30, 2011 was $1,652,325 and $1,880,591, respectively, compared to $411,258 and $743,636, respectively for the same periods in 2010. Depletion and depreciation was higher in these 2011 periods due to the addition of production volumes from the Company's Turkish operations. Depletion is calculated over proved plus probable reserves.

On a per unit basis, depletion and depreciation for the three and six months ended June 30, 2011 was $26.26/boe and $24.44/boe, respectively, compared to $17.18/boe and $16.36/boe for the same periods in 2010. Depletion and depreciation on a per unit basis are higher due to the Edirne and TBNG-PTI acquisitions.

Deferred tax

For the three and six months ended June 30, 2011, the Company recorded a deferred tax recovery of $297,360. This deferred tax recovery was recognized as a result of changes in the temporary difference between the net book value and the tax basis of the assets and liabilities in the Company's Turkish operations.

Currency translation adjustments

Translation of all assets and liabilities from the respective functional currencies to the reporting currency are performed using the rates prevailing at the balance sheet date. The differences arising upon translation from the functional currency to the reporting currency are recorded as currency translation adjustments in other comprehensive income or loss ("AOCI") and are held within AOCI until a disposal or partial disposal of a subsidiary. A disposal or partial disposal will then give rise to a realized foreign exchange gain or loss which is recorded in net earnings.

The currency translation adjustment loss for the three and six months ended June 30, 2011 was $1,576,323 and $1,576,636 respectively. The currency translation loss is related to the decline in value of the Turkish Lira when compared to the Canadian Dollar throughout the second quarter of 2011. The company had no currency translation adjustments in the first six months of 2010.

Capital Expenditures

The following summarizes the Company's capital spending:

	Three months ended		Six months ended	
Turkey	**June 30, 2011**	June 30, 2010	**June 30, 2011**	June 30, 2010
Geological and geophysical	**$ 78,667**	$ -	**$ 196,467**	$ -
Drilling, completions and equipping	**1,800,898**	-	**3,993,038**	-
Asset acquisitions	**53,724,623**	-	**55,671,073**	-
Turkey total	**55,604,188**		**59,860,578**	-
Canada total	**46,418**	449,670	**(12,010)**	843,847
Consolidated total	**$ 55,650,606**	$ 449,670	**$ 59,848,568**	$ 843,847

Turkey

Anatolian Basin

During the three and six months ended June 30, 2011, the Company incurred $913,414 and $2,898,352, respectively, of capital expenditures dedicated to Phase 1 of the AME-GYP farm-in agreement. The most significant expenditure under the AME-GYP farm-in during Q2 was $850,000 related to the drilling of the Bostanci-1 well at Rubai. The Bostanci-1 drilling costs have been included as impairment in exploration and evaluation expense.

On April 26, 2011, an order was signed by the Minister of Energy and Natural Resources in Turkey cancelling the Rubai exploration licenses for failure to meet the district drilling commitment timeline. These licenses were part of the AME-GYP farm-in agreement and were considered as part of both the Phase I and Phase II earning program. The Bostanci-1 well was spudded prior to the Ministry notice and such costs have been expensed as incurred. Management is reviewing its work plan on the AME-GYP farm-in lands to re-assess the scope of any optional Phase II expenditures. Valeura has applied for an exploration license covering an area encompassing one of the expired Rubai licenses where the Bostanci-1 well had been spudded. This application will not fall within the AME-GYP farm-in.

Thrace Basin

On June 8, 2011, The Company completed the acquisition of certain producing natural gas assets in the Thrace Basin in Turkey ("TBNG-PTI asset acquisition") for an adjusted purchase price of $53.7 million. The assets consist of a 40% non-operated working interest in certain onshore production and exploration licenses and varying interests in other offshore licenses in the Thrace Basin and other licenses in the Gaziantep area of southeast Turkey. The acquisition was comprised of $28.9 million of property, plant and equipment and $24.8 million of exploration and evaluation assets.

The capital program on the TBNG-PTI lands continued after closing of the acquisition. Valeura recorded $759,000 of capital associated with drilling and work-over operations on the TBNG-PTI lands in the second quarter of 2011. The Company also spent $205,000 on drilling and work-over operations for the previously acquired Edirne assets in Q2 2011.

On March 24, 2011, the Company completed the acquisition of certain producing natural gas assets in the Thrace Basin in Turkey ("Edirne asset acquisition") for an adjusted purchase price of $1.95 million at March 24, 2011. The assets consist of a 35% non-operated working interest in the Edirne Exploration license 3839. The acquisition was comprised of $1.3 million of property, plant and equipment and $0.7 million of exploration and evaluation assets.

The following table reconciles PP&E and E&E expenditures from the statement of cash flows:

	Three months ended		Six months ended	
Property, plant and equipment	**June 30, 2011**	June 30, 2010	**June 30, 2011**	June 30, 2010
Canada	**$ 46,418**	$ 449,670	**$ (12,010)**	$ 748,052
Acquisition of TBNG-PTI assets	**28,892,627**	-	**28,892,627**	-
Acquisition of Edirne assets	**-**	-	**1,280,150**	-
Drilling, completions and equipping	**66,715**	-	**66,715**	-
	29,005,760	$ 449,670	**30,227,482**	$ 748,052
Exploration and evaluation				
Canada	**-**	-	**-**	95,795
Acquisition of TBNG-PTI assets	**24,831,996**	-	**24,831,996**	-
Acquisition of Edirne assets	**-**	-	**666,300**	-
Geological and geophysical	**78,667**	-	**196,467**	-
Drilling, completions and equipping	**1,734,183**	-	**3,926,323**	-
	26,644,846	-	**28,621,086**	-
Total capital expenditures	**$ 55,650,606**	$ 449,670	**$ 59,848,568**	$ 843,847

Liquidity, Financing and Capital Resources

	Six months ended	
	June 30, 2011	June 30, 2010
Opening cash position	**$ 19,460,311**	$ -
Cash outflow from operations	**(3,546,565)**	(1,233,190)
Capital expenditures	**(59,848,568)**	(843,847)
Decommissioning costs incurred	**(54,124)**	-
Cash received on business combination	**-**	6,043,902
Net change in credit facility	**-**	(3,759,592)
Share issuance, net of costs	**81,066,022**	29,272,973
Working capital changes	**(4,572,231)**	(932,724)
Closing cash position	**$ 32,504,845**	$ 28,547,522

Capital Funding and Resources

As at June 30, 2011, Valeura's working capital balance was $37,101,075. The Company's credit facilities have no amounts drawn at the date of this MD&A.

The Company's cash position will be the primary source of capital for all exploration and development expenditures in 2011. Valeura's opening cash position in 2011 was $19,460,311. After closing of the private placement totaling $81,066,022 (net of share issuance costs); acquiring producing natural gas assets for $55,671,073 and funding six months of the 2011 capital program in the amount of $4,177,495 (total capital expenditures of $59,848,568); incurring decommissioning costs of $54,124; and funding negative cash flow from operations of $3,546,565, the Company has $32,504,845 of cash on June 30, 2011.

Bank Facility

Valeura's credit facilities are with a Canadian chartered bank and are comprised of a $1,900,000 revolving operating demand loan at an interest rate of bank prime plus 1.25% and a $1,000,000 development demand loan at an interest rate of bank prime plus 1.50%. The revolving operating demand loan was reduced from $2,650,000 which was in place in the prior three month period ended March 31, 2011. The credit facility is secured by a first floating charge demand debenture in the amount of $10,000,000 and a general security agreement over all assets. As at June 30, 2011, there were no amounts owing under the facility. Pursuant to the terms of the credit facility, the Company is subject to a financial covenant with respect to working capital with which the Company was in compliance at June 30, 2011. The credit facilities are scheduled for review on December 31, 2011.

Upon closing the TBNG-PTI acquisition in the second quarter of 2011, the Company is in a position to expand its borrowing capacity with the addition of production and cash flow in Turkey. The process to review proposals for a potential international lending facility has been initiated with results expected during the fourth quarter of 2011.

Financial Capacity

At the end of Q2 2011, the Company's working capital position was approximately $37.1 million. The combination of this working capital surplus plus estimated operating cash flow after G&A of $6 to $8 million for the second half of 2011 is sufficient to fund an estimated capital program of approximately $20 million in 2011. This financial position combined with an anticipated expanded bank loan facility is expected to provide the Company with financial capacity to expand its drilling program or complete further acquisitions in 2011.

Capital Management

The Company's objective when managing capital is to maintain a flexible capital structure which allows it to execute its growth strategy through strategic acquisitions and expenditures on exploration and development activities while maintaining a strong financial position. The Company's capital structure includes working capital, bank loans and shareholders' equity. At this point in time, total capital resources available include working capital plus the unused portion of the Company's credit line.

The Company's capital expenditure includes expenditures in oil and gas activities which may or may not be successful. The Company makes adjustments to the capital structure in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. In order to maintain or adjust the capital structure, the Company may, from time to time, issue shares, adjust its capital spending or issue debt instruments. The Company is not subject to any externally imposed capital requirements other than covenants on its credit facility with its lender to maintain an adjusted working capital ratio of not less than 1 to 1 at all times. At June 30, 2011, the Company's adjusted working capital ratio was 9.9 to 1.

Valeura has not utilized bank loans or debt capital to finance capital expenditures to date. It is expected that the Company bank loan capacity has increased with the expansion of its operations in Turkey. In the future, if the Company borrows on its bank loan facility for capital expansion, the Company will monitor capital based on the ratio of net debt to annualized funds from operations or any other covenants under a potential international lending facility. This ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant.

Share Capital

As at August 24, 2011, Valeura had 464,061,475 common shares, 21,138,615 options to purchase common shares, and 160,659,675 warrants (comprised of 29,967,500 performance warrants and 132,692,175 common share purchase warrants) issued and outstanding (645,859,765 common shares fully diluted).

Selected Quarterly Information

	Three months ended			
	June 30, 2011	March 31, 2011	December 31, 2010	September 30, 2010
Total daily production (boe/d)	692	156	193	243
Average wellhead price ($/boe)	43.02	40.13	38.63	35.54
Petroleum and natural gas sales	$ 2,707,193	$ 562,132	$ 686,097	$ 794,216
Funds from operations	(1,622,240)	(1,924,325)	(879,447)	(682,651)
$ per share (basic and diluted)[1]	(0.01)	(0.01)	(0.01)	(0.00)
Net loss	(4,359,006)	(4,262,009)	(3,350,588)	(3,171,965)
$ per share (basic and diluted)[1]	(0.04)	(0.02)	(0.02)	(0.02)

	Three months ended			
	June 30, 2010	March 31, 2010	December 31, 2009	September 30, 2009
Total daily production (boe/d)	263	239	254	336
Average wellhead price ($/boe)	37.35	40.07	36.43	29.02
Petroleum and natural gas sales	$ 892,878	$ 861,347	$ 851,807	$ 897,873
Funds from operations	(885,673)	(347,517)	(132,008)	(176,177)
$ per share (basic and diluted)[1]	(0.01)	(0.01)	(0.00)	(0.00)
Net loss	(3,194,474)	(1,707,111)	(575,303)	(1,174,449)
$ per share (basic and diluted)[1]	(0.02)	(0.03)	(0.01)	(0.02)

Note 1: The average number of common shares outstanding was not increased for outstanding stock options and performance warrants as the effect would be anti-dilutive.

The 2010 and 2011 quarterly results have been adjusted to conform to IFRS. The quarterly results for 2009 have not been adjusted and reflect the results in accordance with previous GAAP.

Significant factors and trends that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Over the past two years, the price of natural gas in Canada has been negatively impacted by an increasing supply of natural gas coming from new technology tapping into abundant supplies of tight shale gas reservoirs in North America. With depressed natural gas prices in Canada, Valeura has focused its capital expenditures towards international development with higher netbacks. The impact of this strategy is expected to be fully visible in second half of 2011.
- The Company incurred impairment charges of $1,478,228 on its Canadian operations in 2010 and $2,280,120 on its Turkish operations in the first six months of 2011.
- The Company has incurred significant transaction costs of $1.9 million for 2011 related to acquisitions. This level of transaction costs is not expected to recur in the near future.

Segmented Information

	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Petroleum and natural gas revenue				
Canada	**$ 539,650**	$ 892,878	**$ 1,017,767**	$ 1,754,225
Turkey	**2,167,543**	-	**2,251,558**	-
	2,707,193	892,878	**3,269,325**	1,754,225
Net loss				
Canada	**(3,176,843)**	(3,194,474)	**(5,965,512)**	(4,901,585)
Turkey	**(1,182,163)**	-	**(2,655,503)**	-
	(4,359,006)	(3,194,474)	**(8,621,015)**	(4,901,585)
Capital expenditures				
Canada	**46,417**	449,670	**(12,010)**	843,847
Turkey	**55,604,189**	-	**59,860,578**	-
	$ 55,650,606	$ 449,670	**59,848,568**	843,847
Total assets				
Canada			**47,652,462**	42,349,404
Turkey			**80,191,056**	-
			$ 127,843,518	$ 42,349,404

Commitments

The Company has completed five transactions in Turkey and now holds interests in approximately 2.6 million gross acres (1.0 million net), assuming all farm-in interest are earned which will require fulfillment of certain capital programs.

On September 1, 2010, the Company entered into a farm-in agreement on lands held under the AME-GYP farm-in agreement. The farm-in allows Valeura to earn varying working interests in a production lease and one group of exploration licenses in southeast Turkey. The agreement stipulates a Phase I minimum earning program of US$8.8 million and an optional Phase II program of the same amount to increase earning expenditures up to a maximum of US$17.6 million. The working interest earned in the production lease and the group of licenses is based on a sliding scale (between the minimum and maximum earning expenditures) to be determined based on final capital expenditures incurred. No interests are earned unless the Phase I earning program is completed. As of June 30, 2011, US$8.45 million was recorded as capital with an additional US$750,000 advanced to AME-GYP.

Spending to-date includes $2,259,607 on the Rubai licenses in southeast Turkey. Although these licenses expired, the expenditures count towards earning on the remaining lands under terms of the AME-GYP farm-in agreement. The additional Phase II program of US$8.8 million is discretionary under the farm-in agreement and is currently under review. If any Phase II expenditures are incurred, an additional success fee of 1.5% is due and payable, in accordance with an executed consulting services agreement, on the total Phase II expenditures incurred, up to a maximum of 1.5% of US$8.8 million. The success fee, if any, will be paid in Valeura shares and is calculated by dividing the success fee by the volume weighted average trading price of Valeura for the five days prior to the date the contingent payment is owed.

The Company has until December 31, 2011 to incur expenditures and earn interests in the production lease and exploration licenses under the AME-GYP farm-in agreement. The earning program to-date has included evaluating the Kahta mature heavy oil field for further reservoir development and production, recompleting two indicated oil discovery wells, shooting seismic and drilling two exploration wells on previously unexplored lands.

On May 4, 2011, the Company completed a farm-in to earn 100 percent working interest in License 4201 (Marhat farm-in) in the Thrace Basin. The license requires a commitment to drill two wells at a cost of approximately US$3.0 million. The Company expects to drill these wells in 2012.

On June 13, 2011, the Company completed a farm-in to earn 50 percent working interest in Licenses 4094 and 4532 (TransAtlantic farm-in) in the Thrace Basin. The combined licenses require the commitment to drill two wells and spend approximately US$3.0 million on seismic. The Company plans to drill the first well and initiate the seismic program in 2011. The estimated committed expenditure is anticipated to be US$2.5 million in 2011 with a further US$3.5 to US$4.5 million in 2012.

The ultimate recovery of property and equipment costs in Turkey is dependent upon the Company fulfilling its minimum obligation to earn an interest in the AME-GYP lands and upon the existence and commercial exploitation of petroleum and natural gas reserves on undeveloped lands. Uncertainties affect the recoverability of these costs as the recovery of the costs outlined above is dependent upon the Company obtaining government approvals, obtaining and maintaining licenses in good standing and achieving commercial production.

Related Party Transactions

(a) During the three and six months ended June 30, 2011, the Company incurred legal fees of $363,795 and $834,855, respectively (three and six months ended June 30, 2010 - $482,801 and $789,501) from a legal firm in which a partner acts as the Company's Corporate Secretary.

(b) During the three and six months ended June 30, 2011, the Company incurred $nil (three and six months ended June 30, 2010 - $44,371 and $67,971) in consulting fees and expenses from a corporation whose principal shareholder is a director of the Company.

New Accounting Pronouncements and Policies

International Financial Reporting Standards

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Note 17 to the interim consolidated financial statements provides reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial position as at June 30, 2010 and consolidated statements of income and comprehensive income for the three and six months ended June 30, 2010.

The following provides summary reconciliations of Valeura's January 1, 2010 previous GAAP to IFRS transitional Summary Statement of Financial Position reconciliations along with a discussion of the significant IFRS accounting policy changes:

Summary Statement of Financial Position Reconciliations
As at Date of IFRS Transition – January 1, 2010

	Previous GAAP (December 31, 2009)	Effect of transition to IFRS	Note	IFRS (January 1, 2010)
Current assets	$ 587,275	$ -		$ 587,275
Property, plant and equipment	11,415,791	-	1,2	11,415,791
Deferred taxes	139,200	-		139,200
Deferred transaction costs	200,000	(200,000)	8	-
	$ 12,342,266	$ (200,000)		$ 12,142,266
Current liabilities	$ 5,837,988	$ -		$ 5,837,988
Decommissioning obligations	186,500	67,400	5	253,900
Deferred premium on flow-through shares	-	58,500	7	58,500
Share capital	10,795,576	280,704	7	11,076,280
Contributed surplus	134,312	30,275	6	164,587
Deficit	(4,612,110)	(636,879)	5,6,7	(5,248,989)
	$ 12,342,266	$ (200,000)		$ 12,142,266

On transition to IFRS, on January 1, 2010, Valeura used certain exemptions allowed under IFRS 1 First Time Adoption of International Reporting Standards. The exemptions used were as follows:

1. Under IFRS, PP&E assets are grouped into areas designated as cash generating units ("CGUs" or "CGU") for the purposes of impairment testing. IFRS 1 provides for the allocation of the previous GAAP net book value of PP&E assets, excluding E&E assets, to CGUs on a pro-rata basis using the reserve volumes or values as at December 31, 2009. Valeura has elected to allocate the PP&E balance using reserve values and at January 1, 2010, the value allocated to the PP&E assets is $11,415,791.

2. Under previous GAAP, impairment testing on oil and gas properties is performed at a cost centre level. Under IFRS, impairment testing is performed at the CGU level. This will result in a greater number of impairment tests. At January 1, 2010, Valeura did not have any impairment on its PP&E under IFRS.

3. Depletion and depreciation of PP&E is calculated using the unit-of-production method under IFRS using proved plus probable reserves. Depreciation of office equipment will continue to be calculated using a declining balance method.

4. IFRS 1 allows Valeura to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations. Valeura elected to use this exemption and therefore did not record any adjustments to retrospectively restate any of its business combinations that have occurred prior to January 1, 2010.

5. Under previous GAAP, Valeura's decommissioning obligation was discounted over its life based on a credit adjusted risk free rate which was 8% at December 31, 2009. Under IFRS, Valeura is required to revalue its liability for decommissioning costs at each balance sheet date using a current liability-specific discount rate. As a result, the Company's decommissioning obligation increased upon transition to IFRS as the liability was re-valued using a discount rate of 4% to reflect the Company's estimated risk-free rate of interest. The re-valued decommissioning obligation at the transition date was $253,900 with the offset being charged to retained earnings as also provided for under the deemed cost election for full cost oil and gas companies.

6. Under previous GAAP, Valeura expensed stock-based compensation on a straight-line basis. Under IFRS, share based payments are expensed based on a graded and accelerated vesting schedule. Valeura also incorporated a forfeiture multiplier rather than account for forfeitures as they occur as was practiced under previous GAAP. The adjustment to contributed surplus to account for the graded vesting and forfeitures was an increase of $30,275 with the offset being charged to retained earnings.

7. Under previous GAAP, the deferred tax liability associated with the renouncement of tax deductions from the issuance of flow through shares was recorded as a reduction in share capital at the time of renouncement. Under IFRS, the difference between the deferred tax liability associated with the renouncement of the tax deductions and the premium price received on the issuance of flow through shares over the market value of the Company's common shares at the time of issue is recorded as a deferred tax expense at the time of the renouncement. This deferred tax expense effectively represents the net loss on the distribution of the tax deductions to investors. The transitional adjustment resulted in an increase of $280,704 to share capital with a resulting offset being charged to retained earnings.

8. Under previous GAAP, deferred transaction costs were recognized. Under IFRS, transaction costs are expensed as incurred.

Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Reserve estimates including production profiles, future development costs, and discount rates are a critical part of many of the estimated amounts and calculations contained in the financial statements. These estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations. These determinations are updated at least on an annual basis.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the interim consolidated financial statements include:

- Impairment testing – estimates of reserves, future commodity prices, future costs, production profiles, discount rates and the market value of undeveloped land.
- Depletion and depreciation - oil and natural gas reserves, including future prices, costs and the reserve base to use in calculation of depletion.
- Decommissioning obligations – estimates relating to amounts, likelihood, timing, inflation and discount rates.

- Stock-based compensation – forfeiture rates and share price volatility.
- Deferred tax expense – estimates relating to the reversal of temporary differences, tax rates substantively enacted, and likelihood of assets being realized.

The following provides summary reconciliations of Valeura's previous GAAP to IFRS results:

Summary Statement of Financial Position Reconciliations
As at December 31, 2010

	Previous GAAP	Effect of transition to IFRS	Note	IFRS
Current assets	$ 21,953,666	$ -		$ 21,953,666
Exploration and evaluation	-	5,389,420	1	5,389,420
Property, plant and equipment	16,547,844	(5,858,675)	2	10,689,169
Goodwill	257,313	(122,818)	3	134,495
	$ 38,758,823	$ (592,073)		$ 38,166,750
Current liabilities	$ 2,256,699	$ -		$ 2,256,699
Decommissioning obligations	487,914	107,080	4	594,994
Share capital	46,554,120	419,904	5	46,974,024
Contributed surplus	3,207,196	1,806,761	6	5,013,957
Accumulated other comprehensive income	-	203	7	203
Deficit	(13,747,106)	(2,926,021)		(16,673,127)
	36,014,210	(699,153)		35,315,057
	$ 38,758,823	$ (592,073)		$ 38,166,750

1. E&E adjustments include the impact of reclassification of E&E assets from PP&E ($6,089,339 increase in E&E) and the transfer of E&E assets to expense on drilling of unsuccessful wells on the Company's Canadian assets ($699,919 decrease in E&E).
2. The PP&E adjustments include the impact of reclassification of E&E assets ($6,089,339 decrease in PP&E), lower depletion as a result of using proved plus probable reserves to calculate depletion ($1,617,668 increase in PP&E), impairment on the Company's Canadian CGUs ($1,321,234 decrease in PP&E and $156,994 decrease in goodwill), reduction of capitalized G&A ($80,141 decrease in PP&E), increase decommissioning obligations ($15,935 increase in PP&E), and a decrease of capitalized stock-based compensation (1,564 decrease in PP&E).
3. Goodwill adjustments include the impact of recalculating the decommissioning provision on the PanWestern acquisition in Q2 ($34,176 increase in goodwill) and impairment on one of the Company's Canadian CGUs ($156,994 decrease in goodwill).
4. Includes the adjustment to revalue the liability to a risk-free interest rate of 3.5% at December 31, 2010.
5. See January 1, 2010 IFRS adjustments disclosure.
6. Includes recalculation of stock-based compensation incorporating graded accelerated vesting and a forfeiture multiplier.
7. Includes recalculation of translation gains on the Company's subsidiaries operating with a functional currency of Turkish Lira and translating to the Canadian Dollar for presentation purposes.

Summary Net Earnings Reconciliations

	Annual	Q4-2010	Q3-2010	Q2-2010	Q1-2010
Net loss – previous GAAP	$ (9,134,996)	$ (2,045,583)	$ (2,198,913)	$ (3,145,674)	$ (1,744,826)
Addition/(deduction):					
General and administrative	(80,141)	(18,566)	(12,828)	(29,236)	(19,511)
Stock-based compensation	(1,778,050)	(506,503)	(445,369)	(460,277)	(365,901)
Exploration and evaluation	(699,919)	(90,640)	(513,484)	-	(95,795)
Depletion and depreciation	1,617,668	338,041	443,663	437,342	398,622
Decommissioning accretion	10,431	2,944	3,116	3,371	1,000
PP&E impairment	(1,478,228)	(1,030,078)	(448,150)	-	-
Foreign exchange	(203)	(203)	-	-	-
Deferred transaction costs	200,000	-	-	-	200,000
Deferred tax	(80,700)	-	-	-	(80,700)
	(2,289,142)	(1,305,005)	(973,052)	(48,800)	37,715
Net loss – IFRS	$(11,624,138)	$ (3,350,588)	$ (3,171,965)	$ (3,194,474)	$ (1,707,111)

Impact of Transition to IFRS on 2010 Results:

- Exploration and Evaluation ("E&E) – In 2010, Valeura incurred $6,089,339 of E&E expenditures drilling wells in Canada and meeting its AME-GYP farm-in obligations. $699,919 of this amount was reclassified from E&E assets to E&E expense upon determination of unsuccessful Canadian drilling operations.

- Impairment of PP&E – Under IFRS, impairment tests of PP&E are performed at a CGU level as opposed to the entire Company's PP&E balance with a full cost ceiling test under previous GAAP. Impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using fair value less costs to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. In the third quarter of 2010, as a result of decreased Canadian natural gas prices and a subsequent decrease in the Company's future natural gas prices used in the Company's reserves, Valeura incurred a $448,150 impairment charge in one Canadian CGU. Further deterioration in future natural gas pricing in the fourth quarter of 2010, resulted in the Company incurring an additional $1,030,078 impairment charge on the two natural gas weighted CGUs in Canada. PP&E impairments can be reversed in the future if the recoverable amount increases.

- Depletion and depreciation expense – Under IFRS, Valeura has chosen to calculate the depletion expense utilizing proved plus probable reserves as opposed to only proved reserves under previous GAAP. This has resulted in a reduction of depletion and depreciation expense of $1,617,668 in 2010.

New standards and interpretations not yet adopted:

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments; Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting IFRS 9.

- IFRS 10 – "Consolidated Financial Statements" builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included in the consolidated financial statements of the parent company.
- IFRS 11 – "Joint Arrangements" establishes the principles for financial reporting by entities when they have an interest in jointly controlled operations.
- IFRS 12 – "Disclosure of Interest in Other Entities" provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.
- IFRS 13 – "Fair Value Measurement" defines fair value and requires disclosure about fair value measurements.
- IAS 19 – "Employee Benefits" revises the existing standard to eliminate options to defer the recognition of gains and losses in defined benefit plans, requires remeasurement of a defined benefit plan's assets and liabilities to be presented in other comprehensive income and increases disclosure.
- IAS 27 – "Separate Financial Statements" revised the existing standard which addresses the presentation of parent Company financial statements that are not consolidated financial statements.
- IAS 28 – "Investments in Associates and Joint Ventures" revised the existing standard and prescribes the accounting for investments and set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The Company has not completed its evaluation of the effect of adopting these standards on its financial statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting:

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

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. 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 January 1, 2011 and ending on June 30, 2011 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 such period that have 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.

Off Balance Sheet Arrangements

The Company had no off balance sheet arrangements outstanding as at June 30, 2011 and there are no arrangements outstanding at the date of this MD&A other than the credit facilities in favour of the bank which are secured through the existing $10,000,000 floating charge debenture.

Financial Instruments

Financial instruments of the Company include accounts receivable, accounts payable and accrued liabilities and the credit facility. The carrying values of the financial instruments approximate their fair values due to their relatively short periods to maturity. Borrowings under the bank credit facilities are market rate based.

Business Risks and Uncertainties

There are a number of risk factors that the Company faces as participants in the Canadian and international oil and gas industries, which are inherently risky. Certain key risk factors are discussed below:

Foreign Operations

The Company pursues operations outside of Canada. As such, the Company's operations will be subject to a number of risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties as well as government control over domestic oil and gas pricing. Problems may also arise due to the quality or failure of locally obtained equipment or technical support, which could result in failure to achieve expected target dates for exploration operations or result in a requirement for greater expenditure. In addition, the Company is a non-operator on the majority of its properties in Turkey and may not always be able to reach agreement with its partners, which could negatively impact costs and timing.

The Company will operate in such a manner as to minimize and mitigate its exposure to these risks. However, there can be no assurance that the Company will be successful in protecting itself from the impact of all of these risks.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company in Turkey or Canada will be affected by numerous factors beyond its control. The Company's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. The Company's revenues, profitability, future growth and the carrying value of its oil and gas properties, provided such properties yield production, are substantially dependent on prevailing prices of oil and gas.

The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The exchange rates between the Canadian and US Dollar and Canadian Dollar and Turkish Lira also affects the profitability of the Company.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar will negatively impact the Company's production revenues. Future Canadian/United States and Canadian/Turkish Lira exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators. The Company's functional currency in its subsidiary operations in Turkey is the Turkish Lira. The revenue stream will be translated into Turkish Lira from US Dollars for crude oil, is based in Turkish Lira for natural gas, and the majority of costs will be incurred in Turkish Lira. Increases in the value of the Turkish Lira could result in increases in the cost of operations. Decreases in the value of the Turkish Lira could result in decreases in revenue. To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract. An increase in interest rates could result in a significant increase in the amount the Company may be required to pay to service debt.

Volatility of Commodity Prices

Prices for oil and natural gas fluctuate in response to changes in the supply of and demand for petroleum and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Company's control. Oil prices are determined by international supply and demand. Factors which affect oil prices include the actions of OPEC, world economic conditions, government regulation, political stability throughout the world, the availability of alternative fuel sources and weather conditions. Natural gas prices in Canada and internationally are affected by supply and demand, weather conditions and by prices of alternative sources of energy.

World oil prices are quoted in United States dollars and the price received by the Company is affected by the Canadian/US dollar exchange rate, which will fluctuate over time. Turkish natural gas prices are quoted in Turkish Lira and the price received by the Company is affected by the Canadian Dollar/Turkish Lira exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar may negatively impact production revenues. Such increases may also negatively impact the future value of reserves as determined by independent evaluators. In recent years, the Canadian Dollar has increased materially in value against the United States dollar. In recent months, the Canadian Dollar has appreciated in value against the Turkish Lira.

The impact on the oil and gas industry, in general, from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increases in cost during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline. This volatility causes significant variation in net production revenue for the Company from period to period. In an environment of low prices, certain wells or other projects may become uneconomic and the Company may elect not to produce from certain wells, leading to a reduction in development opportunities and the volume and value of reserves.

Volatile oil and gas prices make it difficult to estimate the acquisition value of producing properties and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Capital Requirements

The impact on capital markets caused by investor uncertainty in the global economy has a significant impact on the Company's business model. The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. There can be no assurance that debt or equity financing will be available or that cash generated by operations will be sufficient to make these expenditures. If debt or equity financing is available, it may not be on terms acceptable to the Company. Failure to obtain such financing on a timely basis could cause the Company to miss certain acquisition opportunities.

Third Party Credit Risk

The Company must successfully market its oil and natural gas to prospective buyers. The Company may be exposed to third party credit risk through its contractual arrangements with its current or future marketers of its oil and natural gas production. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material impact on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program unless sole risk provisions are available under the joint venture agreements.

Exploration, Development and Production

The long-term commercial success of the Company will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisition or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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

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

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company is not always able to control these risks when it is a non-operator.

Uncertainty of Reserve Estimates

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, engineering and economic data; therefore, reserves estimates are inherently uncertain. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, many factors and assumptions are incorporated such as expected reservoir characteristics based on geological, geophysical and engineering assessments, future production rates based on historical performance and expected future operating and investment activities, future oil and gas prices and quality differentials, future development and operating costs and assumed effects of regulation by government agencies.

Properties will, over a period of time, actually deliver oil and natural gas in quantities different than originally estimated due to changes in reservoir performance. The timing of future capital expenditures is subject to uncertainty. Projected future commodity prices and the operating and capital cost structure are subject to significant management judgment and currently, highly volatile. Actions by Canadian provincial governments and foreign governments to alter their respective royalty and tax regimes may have a significant and unpredictable impact.

Environment, Health and Safety

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. In Canada and other international jurisdictions, environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. There are potential risks to the environment inherent in the business activities of the Company.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The potential inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Insurance

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