DUNDEE ENERGY LIMITED

(formerly Eurogas Corporation)

MANAGEMENT'S DISCUSSION AND ANALYSIS

AS AT AND FOR THE YEAR ENDED DECEMBER 31, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dundee Energy Limited ("Dundee Energy" or the "Corporation") is a Canadian-based company focused on creating long-term value through the development and acquisition of high-impact energy projects. The Corporation holds interests, both directly and indirectly, in the largest accumulation of producing oil and natural gas assets in southern Ontario and in the development of an offshore underground natural gas storage facility in Spain. The Corporation also holds an investment in preferred shares of Eurogas International Inc. ("Eurogas International"), an oil and gas exploration company that holds a 45% participating interest in the one million acre Sfax permit located offshore Tunisia.

The Corporation's common shares currently trade on the Toronto Stock Exchange ("TSX") under the symbol "DEN". Pursuant to a special resolution passed by the shareholders of the Corporation at its annual and special meeting held on June 14, 2011, the Corporation changed its name from "Eurogas Corporation" to "Dundee Energy Limited" in order to more clearly reflect its business operations in the energy sector, both in Canada and in Europe. On June 22, 2011, the common shares of the Corporation commenced trading on the TSX under the new symbol "DEN" (formerly "EUG"). Prior to February 4, 2011, the Corporation's common shares were trading on the TSX Venture Exchange.

This Management's Discussion and Analysis ("MD&A") has been prepared with an effective date of February 15, 2012 and provides an update on matters discussed in, and should be read in conjunction with the Corporation's audited consolidated financial statements as at and for the year ended December 31, 2011 (the "2011 Financial Statements") prepared using International Financial Reporting Standards ("IFRS"). All amounts are in Canadian dollars unless otherwise specified. The financial data discussed in this MD&A, including financial data relating to comparative periods in the prior year, has been prepared in accordance with IFRS (see *"IFRS Adoption"*), unless otherwise specified. Tabular dollar amounts, unless otherwise specified, are in thousands of dollars, except for per unit or per share amounts.

PERFORMANCE MEASURES AND BASIS OF PRESENTATION

The Corporation's 2011 Financial Statements are prepared in accordance with IFRS and use the Canadian dollar as its presentation currency. However, the Corporation believes that important measures of its economic performance include certain measures that are not defined under IFRS and as such, may not be comparable to similar measures used by other companies. Throughout this MD&A, there will be references to the following performance measures which management believes are valuable in assessing the economic performance of the Corporation. While these measures are not defined by IFRS, they are common benchmarks in the oil and natural gas industry, and are used by the Corporation in assessing its operating results, including net earnings and cash flow.

- "Barrel of Oil Equivalent" or "boe" is calculated at a barrel of oil conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of oil (6 Mcf to 1 bbl), based on an energy equivalency conversion method which is primarily applicable at the burner tip and does not always represent a value equivalency at the wellhead.
- "Field Level Cash Flows" is calculated as revenues from oil and natural gas sales, less royalties and production expenditures, adjusted for realized price management contracts. Field level cash flows contribute to the funding of the Corporation's working capital, as well as to capital expenditure requirements for these activities. Field level cash flows also provide for repayment of amounts owing pursuant to the Corporation's credit facilities (see *"Liquidity and Capital Resources"*).
- "Field Netbacks" refers to field level cash flows expressed on a measurement unit or barrel of oil equivalent basis.
- "Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- "Probable Reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
- "Reserve Life Index" is determined by dividing proved reserves by expected annual production. For greater certainty, the reserve life index includes only proved reserves and does not include probable or possible reserves.
- "Per Day Amount" or ("/d") is used throughout this MD&A to reflect production volumes on an average per day basis.

IFRS ADOPTION

In 2010, the Handbook of the Canadian Institute of Chartered Accountants was revised to incorporate IFRS, and required publicly accountable enterprises to apply such standards for financial years beginning on or after January 1, 2011.

The Corporation's 2011 Financial Statements have been prepared in accordance with IFRS, including comparative amounts relating to the prior year. Included in Note 5 to the 2011 Financial Statements is a detailed description of the differences between Canadian generally accepted accounting principles ("Canadian GAAP") and IFRS, as they apply to the Corporation. Note 5 also provides a comparison of the Corporation's audited consolidated financial statements as at and for the year ended December 31, 2010, which were originally prepared using Canadian GAAP, compared with those prepared in accordance with IFRS and included as comparative information in the 2011 Financial Statements.

Concurrent with the transition to IFRS, the Corporation completed an assessment of internal controls over financial reporting and information technology systems to ensure compliance with IFRS, both from a transaction level accounting process as well as for the purpose of financial reporting disclosure requirements. Changes to existing procedures were minor and consisted primarily of establishing processes for the more detailed tracking of oil and gas properties that will better facilitate impairment testing, presentation and disclosure under IFRS.

The Corporation continues to assess amendments and updates to IFRS on an ongoing basis. Future changes to IFRS may significantly modify the Corporation's financial and reporting disclosure requirements.

SIGNIFICANT PROJECTS

The Southern Ontario Assets

Dundee Energy Limited Partnership

On June 29, 2010, Dundee Energy Limited Partnership ("DELP"), a limited partnership that is wholly-owned by the Corporation, acquired a 95% working interest in 65,000 acres of onshore oil properties and a 65% working interest in 902,000 acres of offshore gas properties (the "DELP Acquisition"), all located in and around Lake Erie in southern Ontario. In addition to the oil and gas rights associated with these properties, the Corporation acquired four onshore oil facilities, as well as a 65% ownership interest in an offshore fleet of drilling and completion barges and six gas plants and compressor stations that process offshore dry gas at onshore locations. The DELP Acquisition also included the ownership or licensing of up to 14,680 km of 2-dimensional seismic and 331 km^2 of 3-dimensional seismic.

The Corporation paid $128.6 million for the acquisition of the DELP assets. Approximately $67.8 million of the purchase consideration transferred was funded using the Corporation's working capital, with the balance funded by drawing against the Corporation's $80 million credit facility (see *"Liquidity and Capital Resources"*).

Net Assets Acquired		
Oil and gas properties	$	157,851
Prepaids		751
Inventory		758
Investment in Lake Erie Limited Partnership		300
Accounts receivable		150
		159,810
Decommissioning liability		(31,202)
	$	128,608

Transaction costs, consisting primarily of legal and advisory fees, were $3.1 million. In accordance with IFRS, these costs were expensed as incurred.

The DELP Acquisition provides the Corporation with growth opportunities, including a significant number of development drilling locations, as well as opportunities for well recompletions and the optimization of the existing infrastructure system. Importantly, the DELP Acquisition has provided the Corporation with the potential for the development of natural gas storage reservoirs, the feasibility of which will require further evaluation.

Acquisition of Torque Energy Inc. ("Torque")

On August 4, 2011, the Corporation expanded its operations in southern Ontario through the acquisition of 100% of the outstanding common shares of Torque (the "Torque Acquisition"), a Canadian based oil and natural gas company engaged in the exploration, development and acquisition of oil and natural gas properties. Torque held working interests in 47 wells, including 43 wells in southern Ontario, that are located in relative proximity to the Corporation's existing oil and natural gas interests held through DELP. Torque also had interests in four wells located in Alberta. Net production volumes from the Torque assets included 85 bbl per day of oil and condensate as well as 300 Mcf per day of natural gas. Immediately prior to acquisition, management estimated, with the assistance of independent qualified reserves evaluators and professional engineers, proved reserves of 0.5 million barrels of oil with a reserve life index of 16.3 years, as well as 1.1 billion cubic feet of natural gas with a reserve life index of 10.4 years.

In June 2010, Torque had entered into an agreement with Union Gas, which provides Union Gas with the right to develop new natural gas storage capacity in the Trenton Reservoir located within the Dover East field, where Torque held a 50% non-operating working interest. In exchange, Torque will receive cash payments that are tiered to the developmental work undertaken by Union Gas for natural gas storage. Notwithstanding the transaction with Union Gas, Torque retained the right to further explore, drill and produce petroleum substances from all new and certain existing wells within the Dover East field, subject to maintaining the integrity of the designated storage reservoir.

On December 1, 2011, the Corporation completed the integration of the assets and business processes acquired pursuant to the Torque Acquisition, including Torque's interest in the Union Gas transaction, with its existing operations in southern Ontario, providing the Corporation with efficiencies of scale.

The fair value of the purchase consideration for Torque was $7.1 million, including cash of $6.0 million and the issuance of 1,346,926 common shares of the Corporation with a value of $1.1 million (see *"Liquidity and Capital Resources"*). A summary of the allocation of the aggregate consideration transferred to the fair value of the various identifiable assets and liabilities acquired is as follows:

Net Assets Acquired		
Oil and gas properties	$	10,076
Accounts receivable		1,024
Prepaids		147
		11,247
Bank loan		(1,429)
Accounts payable and accrued liabilities		(519)
Decommissioning liability		(2,169)
	$	7,130

Aggregate transaction costs associated with the Torque Acquisition were $0.4 million and were expensed as incurred.

Castor UGS Limited Partnership and the Castor Project

The Corporation has an indirect interest in a Spanish infrastructure project designed to convert the abandoned Amposta oil field, located off the eastern Mediterranean coast of Spain, to a natural gas storage facility (the "Castor Project"). The Castor Project provides Spain with a dedicated source of easily deliverable natural gas and is expected to help moderate seasonal and daily demand peaks. It will also provide Spain with strategic gas storage, ensuring supply continuity in the event of disruption to its national gas system.

The Castor Project will utilize the abandoned Cretaceous aged carbonate Amposta reservoir for gas storage, with gas injection scheduled to begin in May 2012. The underground gas storage reservoir lies at a depth of 1,800 metres, approximately 22 kilometres off the east coast of Spain in the Mediterranean Sea. The Castor Project includes two offshore platforms; a wellhead platform for 13 wells and a processing platform for processing and other facilities, and an onshore gas treatment plant located in the municipality of Vinaroz. The onshore facilities and offshore processing platform will be linked by a 30-inch diameter pipeline that is 30 kilometres long, including 22 kilometres offshore. The Castor Project was categorized as "A Urgent" in Spain's Energy Infrastructure Plan in 2006 and is one of the first underground gas storage projects being developed under Spain's current energy regulatory regime. Strategically located in a high demand region, it is expected to contribute approximately 25% to Spain's gas storage capacity.

The Corporation's Castor Project is managed by ACS Servicios Communicacions y Energia S.L. ("ACS"), the largest construction group in Spain and a 67% shareholder of Escal. Castor UGS Limited Partnership ("CLP"), the Corporation's 74% subsidiary, holds the remaining 33% interest, providing the Corporation with an effective 25% interest.

CLP has entered into certain agreements with ACS and with Enagas, S.A., ("Enagas"), Spain's top natural gas transportation company, the technical manager of the Spanish gas system and common carrier for the gas network in Spain. These agreements provide that within 15 days of the formal inclusion into the Spanish gas system of the Castor Project, ACS will sell and Enagas will buy 50% of ACS' interest in Escal based on a pre-established pricing formula at which point CLP, ACS and Enagas will each own 33% of the equity of Escal. In addition, and for a period of 180 days after the formal inclusion into the Spanish gas system of the Castor Project, CLP may sell part or all of its shares in Escal to ACS and/or Enagas on essentially the same terms and conditions, including the pre-established pricing formula, as are offered to Enagas.

The agreement with ACS also requires that ACS assume responsibility for all project financing through the construction phase, and until commissioning of the Castor Project and its formal inclusion into the Spanish gas system. Costs during the construction phase, including construction, financing costs associated with the Castor Project and the procurement of cushion gas, are currently estimated at €1.6 billion. These costs are subject to regulatory approval before they are included into the remuneration system. In July 2010, Escal successfully completed a €1.3 billion project financing arrangement with a syndicate of banks to support the cost of the Castor Project. In accordance with the agreements between CLP and ACS, the balance of the funding required for the construction phase of the Castor Project will be borne by ACS. Notwithstanding any funding being provided by ACS, CLP will be entitled to 33% of all distributions from Escal.

Series A Preference Share Investment in Eurogas International Inc.

The Corporation holds a $32,150,000 preferred share investment in Eurogas International, an independent oil and gas company engaged in the exploration and evaluation of its extensive landholdings offshore Tunisia, targeting large scale oil and gas reserves. Eurogas International holds a 45% participating interest, and is the non-operating partner in the Sfax offshore permit covering 908,425 acres located in the Gulf of Gabes, in the Mediterranean waters immediately offshore and southeast of the city of Sfax.

The Series A Preference Shares rank in priority to the common shares of Eurogas International as to the payment of dividends and the distribution of assets on dissolution, liquidation or winding up of Eurogas International and entitle the Corporation to a fixed preferential cumulative dividend at the rate of 4% per annum. The Corporation may reinvest any dividends received into common shares of Eurogas International, subject to obtaining the necessary approvals. The Series A Preference Shares may be redeemed at the option of the Corporation or may be retracted by Eurogas International at any time at a price equal to their face value of $1.00 per Series A Preference Share.

The Series A Preference Shares are non-voting except in the event Eurogas International fails to pay the cumulative 4% dividend for eight quarters. Thereafter, but only so long as any dividends on the Series A Preference Shares remain in arrears, the Corporation shall be entitled, voting exclusively and separately as a series, to elect a majority of the members of the Board of Directors of Eurogas International. Notwithstanding the Corporation not receiving any dividends on its investment at December 31, 2011, the Corporation had not exercised its entitlement to elect the majority of the members of the Board of Directors of Eurogas International.

Eurogas International declared a condition of Force Majeure with respect to the Sfax permit and the related Ras El Besh concession, as Eurogas International believes that the political uncertainty and civil unrest in Tunisia adversely affects their ability to continue exploration and evaluation activities in that region. Eurogas International has indicated that it believes that the declaration of Force Majeure will allow Eurogas International and its partner to suspend their activities while the conditions resulting in the Force Majeure continue.

In June 2011, Eurogas International received approval from the Tunisian government for a one-year extension of the expiry date in respect of the Sfax permit to December 8, 2012. As a condition to the extension, Eurogas International and its joint venture partners are committed to drilling one exploration well prior to the maturity date, with depth to a specified geological zone. In the event such work commitment is not completed, a compensation payment of up to US$12 million will be payable to the Tunisian government by the joint venture partners, less certain amounts previously incurred by the joint venture partners associated with such obligation.

CONSOLIDATED RESULTS OF OPERATIONS

Year ended December 31, 2011 compared with the year ended December 31, 2010

Consolidated Net Earnings

During the year ended December 31, 2011, the Corporation incurred a net loss attributable to the owners of the parent of $1.2 million. This compares with a net loss attributable to the owners of the parent of $11.5 million incurred in 2010. A summary of the Corporation's net loss from its various projects is summarized below:

For the year ended December 31,	*2011*			*2010*		
	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest
Southern Ontario assets	$ 1,322	$ 1,322	$ -	$ (4,382)	$ (4,382)	$ -
Castor Project	(261)	(194)	(67)	(636)	(471)	(165)
Loss from investment in preferred shares of Eurogas International	(1,286)	(1,286)	-	(7,262)	(7,262)	-
Corporate activities	(1,088)	(1,088)	-	610	610	-
Net loss for the year	$ (1,313)	$ (1,246)	$ (67)	$ (11,670)	$ (11,505)	$ (165)

Following the DELP Acquisition completed in June 2010, the Corporation began generating revenues from, and incurring expenses related to development and production activities in southern Ontario. As such, the Corporation's operations have changed significantly compared with those during the prior year, where, during the first six months, the Corporation's activities were limited to exploration and development activities related to its Spanish interests.

Included in the Corporation's 2011 operating results in southern Ontario are five months of production activities from Torque. Torque's assets and operations were integrated with the Corporation's existing business activities in southern Ontario on December 1, 2011.

Southern Ontario Assets

In accordance with industry practice, production volumes, reserve volumes and oil and gas sales are reported on a working interest or “net” basis, before deduction of royalty interests.

Production Volumes

The Corporation’s operating performance is dependent on production volumes of oil, natural gas and natural gas liquids, and the prices received for production volumes. Prices for these commodities may vary significantly from year to year and are determined by supply and demand factors, weather, general economic conditions and changes in foreign exchange rates. In 2011, the Corporation reported marginal increases to its average daily production volumes for natural gas, oil and natural gas liquids as tabled below.

Average daily volume during the year ended December 31,	2011	2010
Natural gas (Mcf/d)	10,538	10,435
Oil (bbls/d)	692	669
Liquids (bbls/d)	26	19
Total (boe/d)	2,474	2,427

The Corporation incurred an annual decline rate of approximately 5% to 6% in its natural gas production during 2011 due to required pipeline repairs, resulting in lost production of approximately 30 Mcf/d. The decline was partially offset by the drilling and completion of two successful offshore wells in the fourth quarter of 2011 that will contribute average production volumes of approximately 450 Mcf/d. Also, through the Torque Acquisition, the Corporation acquired natural gas production volume of approximately 300 Mcf/d.

The historical decline rate of approximately 15% in the Corporation’s oil production was offset by drilling, workover and acquisition programs. The Corporation drilled and completed a new oil well in December 2011 that came on production at 23 bbl/d, and it added approximately 85 bbls/d from the Torque Acquisition. The balance of the increase came as a result of successful workover projects.

In 2012, the Corporation’s capital programs will focus on onshore oil projects and will include a number of workover initiatives to further optimize oil and natural gas production from existing fields. In addition, the Corporation continues to assess potential drill opportunities in an ongoing effort to replenish reserves.

Oil and Gas Sales

Revenues from oil and gas sales were $42.2 million in the year ended December 31, 2011. This compares with revenues of $19.5 million earned in the prior year. The Corporation essentially commenced operations on June 29, 2010, following the DELP Acquisition. Therefore, revenues in the comparative period of the prior year represent only two full quarters of operations.

	Twelve months ended December 31, 2011		From commencement of operations on June 29, 2010 to December 31, 2010	
	Sales	Realized Prices ($ / unit)	Sales	Realized Prices ($ / unit)
Natural gas	$ 17,316	4.50	$ 9,190	4.79
Oil	24,302	96.15	10,141	82.38
Liquids	558	59.32	189	55.11
	42,176		19,520	
Less royalties at 15% (2010 - 16%)	(6,358)		(3,040)	
Net sales	$ 35,818		$ 16,480	

The Corporation pays royalties to provincial governments, freehold landowners and overriding royalty owners. Royalties are generally calculated as a percentage of oil and gas sales. In 2011, the Corporation recorded royalty obligations of $6.4 million (2010 - $3.0 million) against its oil and gas sales, representing an average royalty rate of approximately 15% (2010 – 16%).

Effect of Commodity Prices on Revenues from Oil and Gas Sales

	For the year ended December 31, 2011			For the six months ended December 31, 2010		
Benchmark Prices	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Oil						
West Texas Intermediate (WTI)	94.91	93.40	96.15	80.61	83.68	82.38
Edmonton Par		95.73			77.86	
Natural Gas						
Dawn Hub	4.37	4.30	4.50	4.46	4.63	4.79
Nymex Henry Hub	4.00	3.93		4.30	4.46	

Natural gas sales currently represent 71% (2010 – 72%) of the Corporation's overall production volume on a boe basis, and 41% (2010 – 48%) of total revenues from oil and gas sales. Global natural gas inventories, drilling and production remain at near record highs, exerting downward pressure on the price of natural gas. During the year ended December 31, 2011, the Corporation realized an average price of $4.50/Mcf on its sales of natural gas, a decrease of over 6% from the average price of $4.79/Mcf realized in the prior year. Due to the proximity of the Corporation's operations to the Dawn Hub, a leading provider of natural gas supply to the greater Toronto market area, the Corporation's realized price from sales of natural gas includes a positive basis differential from the average industry benchmarks as illustrated in the table above.

Oil currently represents 29% (2010 – 28%) of overall production volumes on a boe basis and generates 59% (2010 – 52%) of total revenues. Global economic uncertainties continue to cause substantial volatility in the price of oil. Concerns over the effect to oil supply from political unrest in the Middle East contrast with the downside risk of decreased demand following austerity measures in the European Union and their effect on consumption in emerging economies such as India and China. These concerns are reflected in the West Texas Intermediate Crude Oil Price, which closed at US$98.83/bbl on December 31, 2011, amid significant volatility with a high of US$113.39/bbl in April 2011, and a low of US$75.40/bbl in October 2011. The Corporation realized an average price of $96.15/bbl from its sales of oil, a 17% increase over $82.38/bbl realized in the prior year.

Risk Management Contracts – Price Risk Management

The Corporation may, from time to time, enter into fixed price contracts and derivative financial instruments for the purpose of protecting its oil and natural gas revenue from the volatility of oil and natural gas prices. The Corporation's revenues are primarily received in Canadian dollars, however, pricing for commodities, including oil and natural gas, are closely referenced to the US dollar. The Corporation partially mitigates its exposure to changes in commodity prices resulting from foreign exchange variability by entering into commodity risk management contracts on a Canadian dollar basis. These price risk management strategies assist the Corporation in securing a stable amount of cash flow to protect a desired level of capital spending and for debt management.

The following is a summary of commodity contracts entered into by the Corporation as of December 31, 2011. These risk management contracts are subject to periodic settlements throughout the term of the contracts. Such settlements may result in a gain or loss, which is recognized as a realized risk management gain or loss at the time of settlement. The effect of these contracts is not reflected in the Corporation's reported amounts of oil and natural gas sales.

Contract	Volume	Pricing Point	Strike Price CDN$/unit	Remaining Term
Fixed Price Swap - Crude oil	500 bbl/day	NYMEX	$101.20	Jan 01/12 to Dec 31/12
Fixed Price Swap - Natural Gas	6500 mbtu/day	NYMEX	$4.66	Jan 01/12 to Feb 29/12
Fixed Price Swap - Natural Gas	7000 mbtu/day	NYMEX	$3.84	Mar 01/12 to Dec 31/12

For accounting purposes, the Corporation has not designated these risk management contracts as hedges. Accordingly, the Corporation is required to estimate the fair values of outstanding contracts at each reporting date and to include changes in the fair values as a component of the Corporation's net earnings. The fair values of risk management contracts outstanding at the end of a reporting period are determined using market conditions and forecasts prevailing as at the reporting date. Any changes in the fair values of risk management contracts from amounts determined at the end of the previous reporting period are recognized as an unrealized risk management gain or loss. An unrealized risk management gain or loss may or may not be realized in subsequent periods depending upon subsequent fluctuations in commodity prices or foreign exchange rates affecting the risk management contracts.

The following table summarizes the realized and unrealized gains or losses from the Corporation's risk management contracts. If risk management contracts were unwound at December 31, 2011, the Corporation would receive an amount of $1.6 million (2010 – obligation of $0.5 million). The positive value of the Corporation's risk management contracts at December 31, 2011 resulted from forecasted decreases in underlying commodity prices during the periods covered, compared with the fixed price pursuant to the terms of the contract itself.

For the years ended December 31,			2011			2010
	Realized (loss) gain	Unrealized gain	Total	Realized loss	Unrealized loss	Total
Oil swaps	$ (62)	$ 403	$ 341	$ (2)	$ (453)	$ (455)
Gas swaps	1,065	1,666	2,731	-	-	-
	$ 1,003	$ 2,069	$ 3,072	$ (2)	$ (453)	$ (455)

Production Expenditures

			Twelve months ended December 31, 2011			From commencement of operations on June 29, 2010 to December 31, 2010
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Production expenditures	$ 7,254	$ 5,703	$ 12,957	$ 3,124	$ 2,595	$ 5,719
Production expenditures ($/unit)	$ 1.89	$ 21.75	$ 14.35	$ 1.63	$ 20.51	$ 12.80

Production expenditures include costs associated with bringing oil and natural gas from the reservoir to the surface sales point, and include separating the oil and gas, treating the oil and gas to remove impurities and disposing of produced water. Included in production expenditures is an allocation of general and administrative costs, including labour, which is directly attributable to these activities.

During 2011, the Corporation incurred production expenditures of $13.0 million or $14.35/boe. Included in production expenditures during 2011 is approximately $0.5 million to repair pipelines, which represents $0.58/boe of the total. Adjusted for this amount, production costs were $13.77/boe during 2011, an increase of 8% over production costs of $12.80/boe incurred in 2010. Generally, the increase in costs reflected increased well workover activity in 2011 compared with 2010, which was the Corporation's first year operating the southern Ontario assets.

Field Level Cash Flows

	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
			Twelve months ended December 31, 2011			From commencement of operations on June 29, 2010 to December 31, 2010
Total sales	$ 17,316	$ 24,860	$ 42,176	$ 9,190	$ 10,330	$ 19,520
Realized risk management gain (loss)	1,065	(62)	1,003	-	(2)	(2)
Royalties	(2,592)	(3,766)	(6,358)	(1,430)	(1,610)	(3,040)
Production expenditures	(7,254)	(5,703)	(12,957)	(3,124)	(2,595)	(5,719)
Field level cash flows	$ 8,535	$ 15,329	$ 23,864	$ 4,636	$ 6,123	$ 10,759

During the year ended December 31, 2011, the Corporation earned field level cash flows of $23.9 million compared with $10.8 million earned in the prior year. Included in field level cash flows is $1.0 million (2010 – negligible) from realized gains on risk management contracts. Field level cash flows should not be considered more meaningful than, or an alternative to, net earnings or loss in accordance with IFRS.

Field Netbacks

	Natural Gas $/Mcf	Oil and Liquids $/bbl	Total $/boe	Natural Gas $/Mcf	Oil and Liquids $/bbl	Total $/boe
			Twelve months ended December 31, 2011			From commencement of operations on June 29, 2010 to December 31, 2010
Total sales	$ 4.50	$ 94.83	$ 46.70	$ 4.79	$ 81.64	$ 43.71
Realized risk management gain (loss)	0.28	(0.24)	1.11	-	(0.02)	-
Royalties	(0.67)	(14.37)	(7.04)	(0.74)	(12.73)	(6.81)
Production expenditures	(1.89)	(21.75)	(14.35)	(1.63)	(20.51)	(12.81)
Field netbacks	$ 2.22	$ 58.47	$ 26.42	$ 2.42	$ 48.38	$ 24.09

Field netbacks from natural gas were $2.22/Mcf in 2011 compared with $2.42/Mcf in 2010. Through its price risk management strategies, the Corporation was successful in maintaining an average realized price of $4.78/Mcf, just slightly below that earned in 2010. However, increased production costs, including costs associated with unexpected repairs and maintenance as previously discussed, adversely affected the Corporation’s field netbacks from natural gas activity.

Field netbacks from oil and liquids were $58.47/bbl in 2011 compared with $48.38/bbl in 2010. Field netbacks have improved largely in response to increasing oil prices.

Capital Expenditures

During the year ended December 31, 2011, the Corporation incurred capital expenditures of $11.1 million on its assets in southern Ontario.

Offshore	
Drilling and completion	$ 2,963
Pipeline	369
Workovers	203
Facilities	164
Offshore fleet	367
Total Offshore	4,066
Onshore	
Drilling and completion	3,341
Workovers	588
Facilities	216
Seismic	1,510
Other	177
Total Onshore	5,832
Undeveloped properties	1,004
Office equipment, computer hardware and software	209
	$ 11,111

As part of its 2011 offshore work program, the Corporation drilled three gas wells at a total cost of $3.0 million. Two wells were drilled, completed and connected to the pipeline grid, and have contributed 450 Mcf/d in gas production. In early November, one of the two producing gas wells temporarily stopped producing due to sand plugging and will be cleaned out in early 2012 and placed back on production. A third well was shut-in pending further evaluation. The Corporation plans to do further analysis on this third well as part of its 2012 work program.

Offshore drilling, completion and workover activities are undertaken with the Corporation's fleet of barges and supply boats, all of which are 65% owned. During the year ended December 31, 2011, the Corporation incurred $0.4 million of costs associated with recertification and annual upgrading of the fleet barges and supply boats.

During the fourth quarter of 2011, the Corporation drilled three wells on its 100% working interest lands in the Rochester oil field. One well was completed in two zones that tested at 23 bbl/d and 40 bbl/d, respectively. Drilling on a third well was suspended at the intermediate casing point and a rig will be moved back onto the site in 2012 to complete the drilling. Drilling costs totalled $3.3 million, of which approximately $2.2 million was incurred in the fourth quarter of 2011. In addition, the Corporation incurred $1.5 million in costs to acquire and process seismic data to identify drill candidates for 2012 and beyond.

Reserves

The Corporation retained AJM Petroleum Consultants ("AJM"), an independent qualified reserves evaluator to prepare a report on the Corporation's working interest of its oil and natural gas reserves in southern Ontario. The Corporation has a Corporate Governance and Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves at December 31, 2011 were determined using the guidelines and definitions set out under National Instrument 51-101. At December 31, 2011, the proved and probable reserves in southern Ontario have increased 10% to 16,091 million boe ("Mboe") from an estimated opening reserve balance of 14,645 Mboe at December 31, 2010. The following table outlines the change in the Corporation's reserves since December 31, 2010.

	Natural Gas	Oil	Natural Gas Liquids	Total		NPV @ 10% Before Tax		
	(mmcf)	*(mbbl)*	*(mbbl)*	*(mboe)*		*(mboe)*		NPV per boe
Proved Reserves								
Opening balance, January 1, 2011	59,711	1,678	47	11,676	$	145,071	$	12.42
Acquired from Torque	589	395	-	493				
Revisions	8,979	(5)	33	1,525				
Production	(3,846)	(253)	(9)	(903)				
Closing balance December 31, 2011	65,433	1,815	71	12,792	$	157,472	$	12.31
Probable Reserves								
Opening balance, January 1, 2011	13,463	708	18	2,969	$	36,574	$	12.32
Acquired from Torque	473	125	-	204				
Revisions	1,005	(55)	13	126				
Closing balance December 31, 2011	14,941	778	31	3,299	$	38,721	$	11.74
Total proved and probable	80,374	2,593	102	16,091	$	196,193	$	12.19
Percentage increase in reserves	10%	9%	57%	10%				

At December 31, 2010, the Corporation estimated the reserve life index for natural gas and oil at 15.5 years and 7.1 years, respectively. As at December 31, 2011, the reserve life index for oil remained unchanged at 7.1 years, while the reserve life index for natural gas increased to 17.1 years.

The following table outlines AJM's forecasted future prices for each of oil and natural gas. These forecasts form the basis for AJM's evaluation of the Corporation's reserves at December 31, 2011 as outlined above.

	Oil	Natural Gas
	Edmonton Par (delivered to Sarnia, ON)	Union Parkway
Reserve Prices	CDN$ / bbl	CDN$ / Mcf
2012	101.80	4.40
2013	103.80	5.00
2014	105.80	5.60
2015	107.80	6.05
2016	109.90	6.45
Average five year forecast	105.82	5.50

2012 Work Program

The Corporation's planned 2012 work program in respect of its assets in southern Ontario is budgeted at $10.6 million on a net basis and includes approximately $8.6 million for onshore projects and $2.0 million for offshore projects.

The 2012 onshore work program is designed to achieve the Corporation's short-term and long-term objectives in respect of its oil developments. Optimizing production in the short-term involves 11 workovers in existing wellbores at a cost of approximately $1.1 million, as well as the drilling of six development wells at a cost of $5.4 million that is expected to increase production and recovery of oil from these reservoirs. Included in the 2012 onshore program is the acquisition of new 3-D seismic over undrilled lands. This expenditure is expected to provide data to design the Corporation's oil optimization program for 2013, enabling it to progress towards its long-term objective of finding, developing and producing new oil reserves. In addition, the Corporation plans to spend $0.4 million upgrading facilities in order to optimize production.

Due to current natural gas prices, the Corporation has decided to limit its offshore program in 2012. The Corporation's 2012 work program includes a cost of $0.5 million towards two workovers. The Corporation has implemented a program to replace aging pipelines and estimates annual expenditures of $0.6 million. Also included in the 2012 offshore program is the acquisition of new seismic and the reprocessing of existing seismic data at a total net cost of $0.9 million.

Decommissioning Liabilities

The Corporation has recorded a decommissioning liability, representing its best estimate of the costs that it will incur to settle future site restoration, abandonment and reclamation obligations. At December 31, 2011, the Corporation's estimate of these future costs on an undiscounted basis is approximately $83.7 million, and is forecasted to be incurred over a 49-year period. During the year ended December 31, 2011, the Corporation incurred $1.0 million on site restoration, abandonment and reclamation expenditures and it anticipates that it will incur an additional $2.0 million towards these obligations within the next twelve months.

In accordance with accounting requirements, the estimated decommissioning liability is recorded in the Corporation's consolidated financial statements on a discounted basis using discount rates that are specific to the underlying obligations. At December 31, 2011, the discounted amount of the Corporation's decommissioning liabilities was $44.3 million. The discount used in calculating the Corporation's decommissioning liabilities is accreted over time. During the year ended December 31, 2011, the Corporation incurred accretion expense of $1.0 million (2010 - $0.5 million). These amounts have been included in the Corporation's 2011 Financial Statements as *"interest expense"*.

Castor Underground Gas Storage Project

The Castor Project continues to progress on schedule and substantially within the approved engineering, procurement and construction budget, reaching an overall completion rate of approximately 95% at December 31, 2011. The offshore processing platform, which was constructed in the United States, was shipped and received at the project site in November 2011, and has been installed and connected to the offshore wellhead platform by way of an interconnecting bridge. Commissioning of systems and equipment tie-ins are progressing as anticipated.

The 13-well drilling program is essentially completed. The Castor 1 well, drilled 6 years ago, has been tied to the wellhead platform. The subsea pipeline, which connects the processing platform to the onshore pipeline, has been laid on the ocean floor. It has been tested and is in the process of being connected to the processing platform.

Construction of the onshore gas treatment plant is mostly complete, with many of the systems already transferred to the operations and maintenance contractors. The pipeline connecting the Castor Project to the Spanish national high-pressure grid has been completed by Enagas, as has the associated metering system, which was also built by Enagas.

Share of (Loss) Earnings from Equity Accounted Investment in Escal

During the year ended December 31, 2011, the Corporation realized a loss of $13,000 (2010 – gain of $4,000) as its share of losses incurred by Escal.

During the first quarter of 2011, Escal established a hedging strategy to mitigate its exposure to interest rate risk associated with the project financing for the construction and development of the Castor Project. At December 31, 2011, the fair value of Escal's obligations in respect of these hedging strategies was approximately €74.8 million (2010 – €nil). Included in the Corporation's other comprehensive loss during the year ended December 31, 2011 is a fair value loss of $4.5 million, representing the Corporation's maximum exposure to Escal's obligations.

During 2010 and 2011, Escal issued shares from treasury with a par value of €12,000. In order to maintain its 33% interest, CLP subscribed for one third of the newly issued par value shares at an aggregate cost of $6,000 (€4,000). In order to meet the equity ratios as required by the project financing, ACS also contributed a share premium of €35.1 million and issued €48.8 million in subordinated loans. CLP has not recognized the benefit of its 33% interest in the share premium and in the subordinated loans as the realization and measurement is subject to a number of risks and uncertainties, including but not limited to, execution risk associated with the construction of the project, the availability and terms of future financing arrangements and the 50-year life span of the project.

Investment in Series A Preference Shares of Eurogas International

Because of the Corporation's entitlement to demand redemption of the Series A Preference Shares at any time from Eurogas International, the Corporation has classified its investment in the Series A Preference Shares as a loan receivable and the associated dividends as interest income. The Corporation has completed an assessment of the fair value of the Series A Preference Shares. In its assessment, the Corporation considered factors such as the delinquency of dividend payments, the financial resources available to Eurogas International to meet current commitments and pursue growth opportunities, and the declaration of Force Majeure. The Corporation concluded that there was significant impairment in the par value of the Series A Preference Shares and the related accrued dividends thereon and accordingly, the Corporation has fully provided against the carrying value of these assets. During the year ended December 31, 2011, the Corporation provided for an impairment loss relating to its investment in Eurogas International of $1.3 million (2010 - $7.3 million).

Other Items in Consolidated Net Earnings

General and Administrative Expenses

General and administrative expenses incurred during 2011 were $8.5 million, a 9% increase from general and administrative expenses of $7.8 million incurred during 2010. Increases in general and administrative expenses reflect increased overall business activities. There were no significant changes in the nature of general and administrative expenses incurred by the Corporation on a year-over-year basis.

Interest Expense

The Corporation incurred interest expense of $4.6 million during 2011, compared with $2.7 million in 2010. Included in interest expense is $1.0 million (2010 - $0.5 million) of accretion expense associated with the Corporation's decommissioning liability.

Interest expense on the Corporation's bank loan was $3.5 million in 2011, an increase of $1.4 million from interest costs of $2.1 million incurred in the prior year. While borrowing amounts and spreads associated with financing costs remained relatively unchanged, prior year amounts included only six months of interest expense, as the bank loan was established mid-year, concurrent with the purchase of the southern Ontario assets.

Income Taxes

The Corporation recognized an income tax recovery of $1.2 million in each of 2011 and 2010, representing an effective income tax rate of 47% and 9%, respectively.

Following the acquisition of Torque in August 2011, the Corporation initiated an assessment of possible income tax strategies that would allow for the utilization of certain tax pools, the benefits of which were previously not recognized by Torque or the Corporation because of uncertainties as to recoverability. However, the subsequent integration of Torque's assets and processes with those of the Corporation allowed for the recognition of these tax pools and accordingly, included in the current year income tax recovery is a recovery of $1.1 million related thereto.

In the prior year, the Corporation incurred a significant provision against the carrying value of its preferred share investment in Eurogas International. For income tax purposes, these amounts are considered capital in nature and accordingly, are only deductible against capital gains. The Corporation did not recognize the $1.9 million income benefit associated with these losses, resulting in a lower effective income tax rate.

As at December 31, 2011, the Corporation's net deferred income tax assets were $3.2 million (2010 - $1.5 million) and included deferred income tax assets of $3.7 million (2010 - $2.2 million) offset by deferred income tax liabilities of $0.5 million (2010 – $0.7 million).

SELECTED QUARTERLY FINANCIAL INFORMATION

The following quarterly information has been presented in accordance with IFRS.

	2011				2010			
	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar
Revenues	$ 9,459	$ 8,757	$ 9,530	$ 8,072	$ 8,301	$ 8,179	$ -	$ -
Net (loss) earnings	985	(1,128)	937	(2,040)	(7,729)	(91)	(3,363)	(322)
Basic and fully diluted (loss) earnings per share	0.01	(0.01)	0.01	(0.01)	(0.05)	-	(0.02)	-
Capital expenditures	4,763	4,109	1,319	920	1,720	2,042	-	3

- The Corporation completed the DELP Acquisition on June 29, 2010. There were no operating revenues prior to the DELP Acquisition.
- In the second quarter of 2010, the Corporation incurred $2.8 million of transaction costs relating to the DELP Acquisition.
- In the fourth quarter of 2010, the Corporation provided $6.3 million against the carrying value of its preferred share investment in Eurogas International and associated accrued dividends.
- In the second and fourth quarters of 2011, the Corporation recognized a $1.9 million gain and a $1.0 million gain, respectively, from its risk management contracts.
- In the third quarter of 2011, the Corporation completed the Torque Acquisition, further increasing revenues in each of the third and fourth quarters by approximately $0.5 million. Also included in the third quarter are $0.4 million of costs associated with this transaction.

QUARTERLY CONSOLIDATED RESULTS OF OPERATIONS

Three months ended December 31, 2011 compared with the three months ended December 31, 2010

During the three months ended December 31, 2011, the Corporation's net earnings attributable to the owners of the parent were $1.0 million or $0.01 per common share compared with a net loss attributable to the owners of the parent of $7.7 million in the fourth quarter of the prior year.

For the three months ended December 31,	*2011*			*2010*		
	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest
Southern Ontario assets	$ 593	$ 593	$ -	$ (2,488)	$ (2,488)	$ -
Castor Project	(112)	(82)	(30)	(120)	(87)	(33)
Loss from investment in preferred shares of Eurogas International	(324)	(324)	-	(6,300)	(6,300)	-
Corporate activities	798	798	-	1,146	1,146	-
Net earnings (loss) for the quarter	$ 955	$ 985	$ (30)	$ (7,762)	$ (7,729)	$ (33)

The Corporation's natural gas production during the three months ended December 31, 2011 was 10,691 Mcf/d compared to production of 10,417 Mcf/d during the same period of the prior year. The increase reflects the drilling and completion of two successful offshore wells, optimization programs and the acquired production associated with the Torque Acquisition. As a result of the Torque Acquisition and the completion of a new oil well which was brought on to production in late 2011, the Corporation's oil production during the three months ended December 31, 2011 averaged 766 bbl/d compared with 669 bbl/d in the fourth quarter of 2010.

Average daily volume during the three months ended December 31,	2011	2010
Natural gas (Mcf/d)	10,691	10,417
Oil (bbls/d)	766	669
Liquids (bbls/d)	27	22
Total (boe/d)	2,575	2,427

Revenues from oil and gas sales were $11.1 million in the fourth quarter of 2011 compared with revenues of $9.8 million earned in the fourth quarter of the prior year. Improved volumes in both oil and gas production represented $0.9 million of the increase.

		Three months ended December 31, 2011			Three months ended December 31, 2010	
		Sales	Realized Prices ($ / unit)		Sales	Realized Prices ($ / unit)
Natural gas	$	3,981	4.05	$	4,309	4.50
Oil		6,920	98.18		5,342	86.82
Liquids		176	71.31		117	58.18
		11,077			9,768	
Less royalties at 14% (2010 - 15%)		(1,559)			(1,467)	
Net sales	$	9,518		$	8,301	

Natural gas sales in the fourth quarter of 2011 represented 69% of the overall production volume on a boe basis. However, with significantly lower gas prices realized by the Corporation, revenues from natural gas sales represented only 36% of total revenue. The Corporation realized an average sales price of $4.05/Mcf in the fourth quarter of 2011, compared with $4.50/Mcf realized in the fourth quarter of the prior year, contributing to a loss in revenues of $0.4 million. As previously indicated, the Corporation earned a positive basis differential from the average benchmark gas prices listed below due in part to the Corporation's proximity to the Dawn Hub.

	For the three months ended December 31, 2011			For the three months ended December 31, 2010		
	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Oil						
West Texas Intermediate (WTI)	93.99	95.62	98.18	85.16	87.29	86.82
Edmonton Par		98.11			80.82	
Natural Gas						
Dawn Hub	3.78	3.85	4.05	4.33	4.44	4.50
Nymex Henry Hub	3.31	3.37		4.18	4.28	

Oil sales in the current quarter represented 31% of overall production volume on a boe basis and 64% of total revenue. During the fourth quarter of 2011, the Corporation realized an average sales price of $98.18/bbl compared to $86.82/bbl in the same period of the prior year, adding $0.8 million to total revenues.

The Corporation incurred production expenditures of $2.2 million during the three months ended December 31, 2011 compared with $2.9 million incurred during the same period of the prior year. Production expenditures in the fourth quarter of 2010 were higher than production expenditures incurred in the fourth quarter of the current year, due to a late start to the seasonal summer work after the DELP Acquisition and commencement of operations.

		Three months ended December 31, 2011			Three months ended December 31, 2010	
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Production expenditures	$ 964	$ 1,284	$ 2,248	$ 1,446	$ 1,480	$ 2,926
Production expenditures ($/unit)	$ 0.98	$ 17.60	$ 9.49	$ 1.51	$ 23.29	$ 13.10

Field level cash flows in the fourth quarter of 2011 were $7.9 million, an increase of 47% from the same period of the prior year. Field level cash flows include a gain of $0.6 million (2010 – negligible) from realized gains on risk management contracts.

		Three months ended December 31, 2011			Three months ended December 31, 2010	
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Total sales	$ 3,981	$ 7,096	$ 11,077	$ 4,309	$ 5,459	$ 9,768
Realized risk management gain (loss)	629	1	630	-	(2)	(2)
Royalties	(582)	(977)	(1,559)	(664)	(803)	(1,467)
Production expenditures	(964)	(1,284)	(2,248)	(1,446)	(1,480)	(2,926)
Field level cash flows	$ 3,064	$ 4,836	$ 7,900	$ 2,199	$ 3,174	$ 5,373

Field netbacks in the fourth quarter of 2011 were favourable compared with field netbacks generated in the fourth quarter of the prior year, due in part to a rise in oil prices, as well as the Corporation's effective hedging strategy against the fall in natural gas prices which resulted in a realized gain of $0.6 million. Field netbacks were also impacted by seasonal decreases in production expenses.

		Three months ended December 31, 2011			Three months ended December 31, 2010	
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
	$/Mcf	$/bbl	$/boe	$/Mcf	$/bbl	$/boe
Total sales	$ 4.05	$ 97.27	$ 46.76	$ 4.50	$ 85.91	$ 43.75
Realized risk management gain (loss)	0.64	0.01	2.66	-	(0.03)	(0.01)
Royalties	(0.59)	(13.39)	(6.58)	(0.69)	(12.64)	(6.57)
Production expenditures	(0.98)	(17.60)	(9.49)	(1.51)	(23.29)	(13.10)
Field netbacks	$ 3.12	$ 66.29	$ 33.35	$ 2.30	$ 49.95	$ 24.07

Other Items in Consolidated Quarterly Earnings

General and administrative expenses incurred in the three months ended December 31, 2011 were $2.7 million compared with $2.4 million incurred in the same period of the prior year. Consistent with year-to-date results, the increase in general and administrative expense reflects increased business activities.

During the quarter ended December 31, 2011, the Corporation incurred interest expense of $1.1 million, primarily on its bank facilities. This was consistent with $1.1 million of interest expense incurred in the same period of the prior year.

Also included in 2011 fourth quarter earnings is an unrealized gain from changes in the fair value of risk management contracts of $0.4 million. This compares with an unrealized loss of $0.4 million incurred in the fourth quarter of 2010.

LIQUIDITY AND CAPITAL RESOURCES

Cash Resources Availability

At December 31, 2011, the Corporation held cash of $2.6 million on deposit with Canadian chartered banks. In addition, the Corporation had access to a further $17.2 million pursuant to its $80.0 million revolving demand credit facility.

Southern Ontario Assets

On June 29, 2010, and in connection with the DELP Acquisition, the Corporation arranged for the establishment of an $80.0 million credit facility, including a $20.0 million operating facility. The credit facility was issued as a direct obligation of DELP, and was placed with a syndicate of Canadian chartered banks. The credit facility is structured as a revolving demand loan, and is subject to a tiered interest rate structure that varies based on DELP's net debt to cash flow ratio, as defined in the credit facility. The interest rate on the credit facility is initially set at prime plus 3% for loans and letters of credit or, for bankers' acceptances, at the bankers' acceptance rate plus 4%. The credit facility is secured against all of the oil and natural gas properties owned by DELP. In addition, the Corporation has assigned a limited recourse guarantee of its units in DELP as further security pursuant to the credit facility. The credit facility is subject to certain covenants, including maintenance of minimum levels of working capital. At December 31, 2011, the Corporation was in compliance with all such covenants.

At December 31, 2011, the Corporation had drawn $62.8 million against the credit facility, including a letter of credit for $3.3 million issued, as required by statute, in favour of the Ministry of Natural Resources in connection with future abandonment and site restoration obligations.

The Corporation assumed, as part of the Torque Acquisition, a $6.1 million revolving demand credit facility established by Torque with a Canadian chartered bank. The credit facility provided Torque with a revolving demand loan, bearing interest at the bank's prime lending rate plus 1.5%. Torque was subject to a standby fee of 0.25% on unused amounts under the credit facility. The credit facility was secured against all of the oil and natural gas properties owned by Torque. The credit facility was fully repaid and cancelled on December 22, 2011.

The Corporation anticipates that cash flows generated from ongoing operating activities, as well as amounts available pursuant to its credit facility, will provide sufficient cash flow to support the ongoing working capital requirements related to the activities in southern Ontario into the foreseeable future.

Spain

ACS is responsible for providing equity and arranging project financing for the Castor Project, including providing all guarantees that may be required, from the day it became a majority shareholder, through development and construction and inclusion of the underground storage facility into the Spanish gas system. After the system is operational, the Corporation will be responsible for its proportionate share of any new capital investments, unless otherwise funded through working capital generated directly by Escal.

Project financing was completed in July 2010, providing Escal with a 10-year, €1.3 billion facility through a syndicate of 19 banks. To provide security for the financing, CLP and ACS have each pledged their respective shares in Escal to the banking syndicate. Other than the pledging of its shares, CLP will not be required to provide any additional equity or debt funds or provide any warranties required by the project finance lenders. Notwithstanding any form by which ACS may fund Escal during the construction phase, CLP's interest in Escal will at all times remain at 33%, and CLP will retain the right to 33% of all distributable cash flows.

Outstanding Share Data

At December 31, 2011, the Corporation had 164,675,147 common shares outstanding. In addition, it had granted 5,665,000 stock options to purchase common shares of the Corporation to directors and key management at a weighted average exercise price of $0.92 per share, and it had issued 603,830 deferred share units.

During the third quarter of 2011, the Corporation completed a private placement with its parent, Dundee Corporation, for 7,243,280 common shares from treasury at a price of $0.83 per share for gross proceeds of $6.0 million. The proceeds from the private placement were used to fund the cash portion of the Torque Acquisition. In addition, the Corporation issued an aggregate of 1,346,926 common shares pursuant to the Torque Acquisition to former Torque shareholders who elected to take common shares of the Corporation in lieu of a cash payment.

During the year ended December 31, 2011, the Corporation purchased 33,512 common shares for cancellation pursuant to its normal course issuer bid at an average cost of $0.85 per common share. Subsequent to December 31, 2011, the Corporation purchased a further 23,500 common shares pursuant to these arrangements at an average cost of $0.61 per common share. At February 15, 2012, the Corporation had 164,651,647 common shares outstanding.

OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Corporation and its subsidiaries have entered into arrangements with several third-party goods and services providers. In certain instances, the Corporation, directly and through its subsidiaries, has provided indemnities and/or guarantees to these third-parties for the payment of goods or services provided, or otherwise. Generally, there are no pre-determined amounts or limits included in these arrangements, and the occurrence of an event that would trigger the Corporation's obligations pursuant to these arrangements is difficult to predict. Therefore, the Corporation's potential future liability cannot be reasonably estimated.

On December 31, 2011, the Corporation had issued a letter of credit for $3.3 million (2010 - $3.3 million) in favour of the Ministry of Natural Resources in connection with future abandonment and site restoration costs.

COMMITMENTS AND CONTINGENCIES

The Corporation has certain lease arrangements that were entered into in the normal course of operations. All leases are treated as operating leases and accordingly, lease payments are included in net operations as incurred. No asset or liability value has been assigned to these leases on the statement of financial position at December 31, 2011.

The following table summarizes payments due for the next five years and thereafter in respect of the Corporation's lease arrangements and other contractual obligations.

	Expected Payments Schedule				
	2012	2013 to 2014	2015 to 2016	Thereafter	TOTAL
Bank loan	$ 59,947	$ -	$ -	$ -	$ 59,947
Decommissioning liabilities	1,985	1,995	2,212	77,547	83,739
Risk management contracts	1,616	-	-	-	1,616
Office, vehicles and equipment leases	340	500	129	-	969
	$ 63,888	$ 2,495	$ 2,341	$ 77,547	$ 146,271

RELATED PARTY TRANSACTIONS

Other than as described in Note 19 to the 2011 Financial Statements, there are no other material related party transactions.

BUSINESS RISKS

There are a number of inherent risks associated with the Corporation's activities and with its current stage of exploration and development. The risks faced by the Corporation are described in the Company's 2011 Annual Information Form dated February 15, 2012, under "*Risk Factors*", which may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") website *www.sedar.com*. These business risks should be considered by interested parties when evaluating the Corporation's performance and its outlook.

ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation’s consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. Critical accounting estimates represent estimates made by management that are, by their very nature, uncertain. The Corporation evaluates its estimates on an ongoing basis. Such estimates are based on historical experience and on various other assumptions that the Corporation believes are reasonable under the circumstances, and these estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amount of revenues and expenses that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. A summary of the significant judgments and estimates made by management in the preparation and analysis of the Corporation’s financial results is included as Note 4 to the 2011 Financial Statements.

CONTROLS AND PROCEDURES

In accordance with the Canadian Securities Administrators’ National Instrument 52-109, the Corporation has filed certificates signed by its Chief Executive Officer and the Chief Financial Officer certifying that, among other things, the design of disclosure controls and procedures and the design of internal control over financial reporting are adequate as at December 31, 2011.

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Corporation in the reports it files or submits under securities legislation is recorded, processed, summarized and reported on a timely basis and that such information is accumulated and reported to management, including the Corporation’s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow required disclosures to be made in a timely fashion. Based on their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as of December 31, 2011, the Corporation’s disclosure controls and procedures were effective.

The Chief Executive Officer and Chief Financial Officer of the Corporation have also evaluated whether there were changes to the Corporation’s internal control over financial reporting during the year ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect the Corporation’s internal control over financial reporting. There were no changes identified during their evaluation. Further, the Corporation has determined that there has been no material change in internal controls over financial reporting as a result of the adoption of IFRS.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements that reflect management’s expectations regarding the Corporation’s future growth, results of operations, performance, business prospects and opportunities. Forward-looking statements include future-oriented financial information, within the meaning of the “safe harbor” provisions of the *U.S. Private Securities Litigation Reform Act of 1995* and the securities legislation of certain of the provinces of Canada, including the *Securities Act* (Ontario).

Certain information set forth in this MD&A, including management's assessment of the Corporation’s future plans and operations, contains forward-looking statements. Forward-looking statements are statements that are predictive in nature, depend upon or refer to future events or conditions and may include words such as “expects”, “anticipates”, “intends”, “plans”, “believes”, “estimates” or similar expressions. In particular, forward-looking statements contained in this document include, but are not limited to, statements with respect to: financial and business prospects and financial outlook; performance characteristics of the Corporation’s oil and natural gas properties; oil and natural gas production levels and reserve estimates; the quantity of oil and natural gas reserves and recovery rates; the Corporation’s capital expenditure programs; supply and demand for oil and natural gas and commodity prices; drilling plans and strategy; availability of rigs, equipment and other goods and services; expectations regarding the Corporation’s ability to raise capital and continually add to reserves through acquisitions, exploration and development; treatment under government regulatory regimes and tax laws; anticipated work programs and land tenure; the granting of formal permits, licences or authorities to prospect; the timing of acquisitions; and the realization of the anticipated benefits of the Corporation’s acquisitions and dispositions. In addition, statements relating to "reserves" or "resources" are, by their nature, forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including risks related to the exploration, development and production of oil and gas, uncertainty of reserve estimates, project development risks, reliance on operators, management and key personnel, the cyclical nature of the oil and gas business, dependence on a small number of customers, the need for additional funding to execute on further exploration and development work, the granting of operating permits and licenses, and other risk factors discussed or referred to in the section entitled *"Risk Factors"* in our annual information form and other documents filed from time to time with the securities administrators, all of which may be accessed at www.sedar.com.

These statements are only predictions, not guarantees, and actual events or results may differ materially. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market share and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

In addition, a number of assumptions were made by the Corporation in connection with certain forward-looking information and forward-looking statements for 2012 and beyond included in this MD&A. These assumptions include: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which the Corporation has an interest to operate such projects in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and/or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; the ability of the Corporation to successfully market its oil and natural gas products; estimates on global industrial production in key geographic markets; global oil and natural gas demand and supply; that the Corporation will not have any labour, equipment or other disruptions at any of its operations of any significance in 2012 other than any planned maintenance or similar shutdowns and that any third parties on which the Corporation is relying will not experience any unplanned disruptions; that the reports it relies on for certain of its estimates are accurate; and that the above mentioned risks and the risk factors described in the Corporation's Annual Information Form do not materialize.

The Corporation's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what resulting benefits the Corporation will derive. The forward-looking statements, including future-oriented financial information, contained herein are presented solely for the purpose of conveying management's reasonable belief of the direction of the Corporation and may not be appropriate for other purposes. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

INFORMATION CONCERNING DUNDEE ENERGY LIMITED

Additional information relating to Dundee Energy Limited, including a copy of the Corporation's Annual Information Form, may be accessed through the SEDAR website at *www.sedar.com* and the Corporation's website at *www.dundee-energy.com*.

Toronto, Ontario
February 15, 2012