Loon Energy Corporation
Management's Discussion and Analysis
For the years ended December 31, 2010 and 2009
(US$, unless otherwise stated)

This Management's Discussion and Analysis ("**MD&A**") document dated April 20, 2011 is provided by the management of Loon Energy Corporation ("**Loon Corp**" or "**Company**") and should be read in conjunction with the audited consolidated financial statements as at, and for the years ended December 31, 2010 and 2009.

Overview

Loon Energy Corporation is an international oil and gas exploration and development company with management offices in Calgary, Alberta, Canada and in Dubai, United Arab Emirates. Loon Corp was incorporated pursuant to the provisions of the *Business Corporation* Act (Alberta) ("**ABCA**") on October 30, 2008 to receive certain of the oil and gas assets of Loon Energy Inc. ("**Loon**") in accordance with a Plan of Arrangement ("**Arrangement**") under the ABCA. Pursuant to the Arrangement, the assets of Loon in Colombia and Peru were transferred to Loon Corp, each Loon shareholder received one common share of Loon Corp for each Loon share held, the common shares of Loon Corp were listed on the TSX Venture Exchange under the symbol LNE and Loon received $3.15 million of cash. The implementation of the Arrangement on December 10, 2008 also resulted in Loon changing its name to Kulczyk Oil Ventures Inc. ("**Kulczyk Oil**").

Additional information relating to Loon Corp can be accessed at www.sedar.com.

Operations Overview

Colombia

Buganviles Association Contract

Through a farm-in agreement, the Company earned a 20% non-operated participating interest in a 60,817 hectare block of land covered by the Buganviles Association Contract between Holywell Resources S.A. and Empresa Colombiana de Petróleos ("**Ecopetrol**"), the Colombian national oil company. The Company earned its interest by paying $1.0 million of the estimated $3.4 million "dry-hole" cost of the Delta-1 well plus 20% of costs incurred thereafter. The Delta-1 well came on production late in September 2008. Ecopetrol approved the operator's Commerciality Application in March 2009, the consequence of which is that fifty percent of the lands would be retained for a period of two years. As such, the license for the Buganviles Association Contract is due for renewal in the second quarter of fiscal 2011. However, the Company and its operator, Pacific Rubiales, do not foresee any issue with obtaining the extension. During the year ended December 31, 2009 the Delta-1 well produced sporadically and was shut in on January 15, 2010. The well remains shut-in as of December 31, 2010. The Company has fulfilled its required work commitments with respect to this contract area. The Buganviles reserves are categorized as "probable".

During fiscal 2010, Loon Corp entered into a farm-out agreement with Petrodorado South America S.A. ("**Petrodorado**") under which Petrodorado agreed to pay Loon Corp's 20% share of the authorized cost to drill and complete two wells in Colombia to earn 75% (net 15%) of Loon Corp's interest in the Buganviles Association Contract, excluding the Delta-1 well. The farm-out agreement included an option for the Company to re-acquire a reversionary interest as further described below. The exercise of this option by the Company in November 2010 reduced the working interest earned by Petrodorado from net 15% to net 10%.

On October 16, 2010, the first of the wells, the Visure-1X exploratory well, commenced drilling and significant oil was encountered in the Lower Guadalupe Formation. The well was perforated and stabilized before being suspended, pending the results of production test analysis. The drilling rig was also released pending evaluation of the production testing. Depending on the results of this analysis, the Company will consider a test in the Upper Guadalupe and Barzalosa Formations. The Operator and the joint venture partners are evaluating production techniques to best develop the discovery in the Lower Guadalupe Formation. The Company's share of the current authorized costs to drill the Visure-1X well is $562,635. The costs to drill Visure-1X are paid by Petrodorado.

The second well, the Tuqueque-1X exploratory well, commenced drilling in the fourth quarter of 2010, but operations on the Tuqueque-1X well were terminated at a depth of 9,303 feet and plans to deepen the well to 11,300 feet were suspended after encountering drilling challenges. The petrophysical evaluation of the upper part of the well indicated three prospective intervals, but testing in 2011 found no appreciable flow of hydrocarbons. The well has been suspended pending further analysis of the testing results.

The Montserrate Formation has potential net pay of 31 feet and is planned to be tested in an updip drilling location later in 2011. The Company's share of the current budgeted costs to drill the Tuqueque-1X well is $1,382,947, the cost of which will be carried by Petrodorado.

The Buganviles Association Contract lands are located in the Upper Magdelena Valley area of central Colombia.

As referenced above, on November 9, 2010, the Company exercised its option to re-acquire a reversion interest of 5% granted to Petrodorado as part of the farm-out agreement. The Company paid Petrodorado for 50% of Loon Corp's 20% share of the authorized completion costs related to the Visure-1X and Tuqueque-1X wells as consideration for the reversion interest. As a result, at December 31, 2010, Loon Corp holds a 10% working interest in the Buganviles Association Contract area.

Abanico Association Contract

The Company currently holds a 49% interest in the area covered by the Abanico Association Contract. The Ventilador-2 well remains suspended throughout the current period. The Company does not anticipate any future activity in the Abanico Association Contract area.

Peru

On August 21, 2007, the Company announced that its wholly-owned subsidiary, Loon Peru Limited ("**Loon Peru**"), signed an exploration license contract with PERUPETRO S.A. granting Loon Peru the right to explore for and produce hydrocarbons from Block 127 in the Marañon Basin area of northeast Peru. Under the terms of the agreement, Loon Peru committed to a minimum work program to acquire, process and interpret 390 kilometres of 2D seismic and reprocess another 2,000 kilometres of 2D seismic during the first two-year exploration period. The gross costs of the phase 1 work commitments were initially estimated at $15 million.

Much of the Company's existing commitments for the first two exploration periods were to be funded by CEPSA Peru S.A. ("**CEPSA Peru**") under the terms of a farm-out agreement dated October 29, 2007. Under the terms of the farm-out agreement, CEPSA Peru earned 80% of Loon Peru's interest in the block in return for consideration consisting of a payment of $700,000 to Loon Peru for past costs, replacement of a $2.25 million performance guarantee that was previously funded by the Company, and payment of the first $10.75 million of expenditures incurred in fulfilling the minimum work commitment for the first exploration period. CEPSA Peru is the operator of Block 127. The Phase 1 work commitments were satisfied in 2010 and the Company's share of total expenditures related to the first exploration period, including the seismic acquisition was $931,625.

In May 2010, PERUPETRO S.A. granted CEPSA Peru a six month extension to the phase 1 exploration period that would enable CEPSA and Loon Peru to finalize the identification of viable drilling targets. On September 30, 2010 CEPSA advised Loon that it did not intend to proceed to the second exploration phase. Efforts to find a partner who would commit to the additional work program required to continue into the next exploration period were not successful and the Company has decided that it will not enter into the second exploration phase with the consequence that it will withdraw from Block 127. With the withdrawal of the Company from Block 127 in Peru, all petroleum and natural gas property expenditures related to Block 127 have been fully written off as at December 31, 2010. CEPSA and the Company are currently developing and executing an abandonment plan for Block 127. All abandonment activities are expected to be completed by the end of 2011.

Selected annual information

	Years ended December 31, 2010	2009	2008
Petroleum and natural gas sales	$ -	$ 46,114	$ 499,133
Less: Royalties	-	(3,689)	(24,768)
	-	42,425	474,365
Less: Operating expenses	-	271,231	194,992
Net operating loss	-	(228,806)	279,373
General and administrative	972,902	544,650	2,374,523
Capital tax expense	16,000	-	-
Stock based compensation	395,452	-	159,965
Loss on foreign exchange	68,731	(105,813)	(687,162)
Depletion, depreciation and accretion	10,201	98,822	399,067
Impairment of petroleum and natural gas properties	1,186,804	-	1,223,386
	2,650,090	537,659	3,469,779
Loss before income taxes	(2,650,090)	(766,465)	(3,190,406)
Income tax (recovery)	(121,786)	75,631	100,000
Net loss	(2,528,304)	(842,096)	(3,290,406)
Net loss per share - basic & diluted	$ (0.03)	$ (0.01)	$ (0.03)

	As at December 31, 2010	2009	2008
Total assets	$ 2,207,819	$ 3,759,705	$ 4,277,328
Long-term financial liabilities (asset retirement obligations)	$ 256,310	$ 126,109	$ 111,293

Oil and Gas Production and Revenue

The Company did not generate oil and a gas revenue for the year ended December 31, 2010. Oil production for the year ended December 31, 2009 was 1,636 barrels at an average price of $29.18 per barrel.

Royalties

For the year ended December 31, 2010, no royalties were paid as no production revenues were generated. 2009 royalties were paid at a rate of 8% on oil sales from the Delta-1 well.

Operating Expenses

Operating expenses for the year ended December 31, 2010 were nil, compared to $271,231 ($165.79 per BOE) in the previous year. The operating costs in 2009 related to oil production at the Delta-1 well, which produced sporadically and was shut-in on January 15, 2010.

General and Administrative Expenses

The general and administrative expenses for the year ended December 31, 2010 were $972,902, compared to $544,650 for the year ended December 31, 2009. The 2010 general and administrative expenses are higher than the comparative period due to increased legal and consulting services in connection with the unsuccessful transaction with Petrodorado and include $451,256 related to the value of shares issued in lieu of salary.

	Year ended December 31, 2010	Year ended December 31, 2009
Salaries and consulting	$ 681,069	$ 111,124
Advisory costs	$ 244,332	$ 375,542
Third party overhead	$ 25,280	$ -
Other administration costs	$ 22,219	$ 57,986
	$ 972,900	$ 544,652

In addition to increased advisory and salary costs, third party overhead charges billed by the Operator in Peru were expensed during fiscal 2010.

Stock based compensation

Stock based compensation expense for the year ended December 31, 2010 was $395,452 compared to nil for the year ended December 31, 2009. The stock based compensation in the current year relates to the issuance of options granted to Directors and other key individuals of the Company on November 25, 2010.

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

Current year DD&A is comprised solely of accretion expense of the asset retirement obligation. Accretion expense for the year ended December 31, 2010 was $10,201 compared to $98,822 of depletion, depreciation and accretion taken in the year ended December 31, 2009.

As a result of the shut-in of the Buganviles contract area on January 15, 2010, no production revenues were generated and no depletion was taken for year ended December 31, 2010. Depletion will not be taken on the petroleum and natural gas assets until such time as production continues. No impairment was required for the Buganviles contract area as sufficient probable reserves exist to support the carrying amount of the asset.

Impairment

Impairment of petroleum and natural gas properties for the year ended December 31, 2010 was $1,186,804 as compared to nil for the year ended December 31, 2009. The impairment is the result of the withdrawal of the Company from Block 127 in Peru. All petroleum and natural gas property expenditures related to Block 127 have been fully written off as at December 31, 2010.

Net Loss

Net loss for the year ended December 31, 2010 was $2,528,304, compared to a net loss of $842,096 for the year ended December 31, 2009. The increase in net loss is due primarily to the impairment of the Peruvian petroleum and natural gas assets and the issuance of stock based compensation.

Property and Equipment Expenditures

	Year ended December 31, 2010	Year ended December 31, 2009
Colombia	$ 18,702	$ 75,011
Peru	390,574	705,691
Total	$ 409,275	$ 780,702

Total property and equipment expenditures for the year ended December 31, 2010 were $409,275, compared to $780,702 in the year ended December 31, 2009. The decrease in 2010 is due to the recovery of prior year expenditures totalling $288,340 billed by the Colombian operator. The decrease in expenditures in Peru is due to decreased activity as a result of the relinquishment of the block.

Summary of Quarterly Data

The following tables set forth selected quarterly financial information for the most recent eight financial quarters.

	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Petroleum and natural gas sales	$ -	$ -	$ -	$ -
Net loss	$ (1,186,546)	$ (1,210,003)	$ (86,419)	$ (53,528)
Per share - basic and diluted	$ (0.03)	$ (0.01)	$ (0.01)	$ (0.01)

	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Production per day				
Oil and NGL's (bbls)	*1*	*5*	*5*	*4*
Petroleum and natural gas sales	$ 8,768	$ 10,897	$ 19,535	$ 6,914
Net loss	$ (269,255)	$ (100,084)	$ (286,438)	$ (186,319)
Per share - basic and diluted	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.01)

The increase in the net loss in Q4 2010, compared to Q3 2010, is the result of the issuance of shares in lieu of salaries in the amount of $441,790, stock options and the related stock based compensation expense and increased general and administrative activities in connection with the unsuccessful transaction with Petrodorado.

The increase to the net loss in Q3 2010 compared to Q2 2010, is due to the impairment of Peruvian petroleum and natural gas properties ($1,186,804) and costs associated with a proposed transaction.

The decrease in the net loss in Q1 and Q2 2010 compared to the respective prior quarters was the result of suspended production and decreased corporate activities.

The increase in the net loss in Q4 2009, compared to Q3 2009, was the result of increased operating expenses as production activities continued and normal general and administrative spending.

The reduced net loss in Q3 2009, compared to Q2 2009, was due to unrealized foreign exchange gains.

The increased net loss in Q2 2009, compared to Q1 2009, was due to a slight reduction in petroleum and natural gas sales as well as an unrealized foreign exchange loss recognized on translation of financial information.

Share Data

The Company is authorized to issue an unlimited number of common shares of which 99,491,364 common shares were outstanding as at December 31, 2010 and March 29, 2010.

The Company is also authorized to issue an unlimited number of preferred shares; there are no preferred shares outstanding.

	Number of Shares	Carrying amount
December 31, 2008 and December 31, 2009	95,991,364	$ 15,139,980
Share issuance	3,500,000	451,256
December 31, 2010	99,491,364	$ 15,591,236

	Years ended December 31	
	2010	2009
Weighted average number of shares outstanding	96,336,569	95,991,364

On November 25, 2010, a total of 3,500,000 shares were issued as compensation for services rendered by certain Officers and Directors of the company. The Company has not issued any preferred shares.

The following table summarizes information about the options outstanding as at December 31, 2010:

Options outstanding			Options exercisable	
Exercise price	Options	Contractual life remaining, years (weighted average)	Options	Exercise price
$ 0.13	9,580,000	4.90	3,193,333	$ 0.13

The fair value of each option granted is estimated as of the grant date using the Black-Scholes option pricing model. The following assumptions were used in arriving at the fair value of $0.01 per option associated with stock options granted during the period:

	December 31, 2010
Risk free interest rate	1.77%
Expected life	2.4 to 3.4 years
Expected volatility	184%
Dividends	Nil

Related Party Transactions

The Company has no employees, and management and administrative services are provided by the management and staff of Kulczyk Oil pursuant to a services agreement. Administrative costs incurred by Kulczyk Oil for the benefit of the Company are allocated to the Company based on specific identification and an allocation of administrative costs that relate to both Kulczyk Oil and the Company. For the year ended December 31, 2010 these fees totalled $11,976 (2009 - $10,550). At December 31, 2010, the Company owed $nil (2009 - $nil) to Kulczyk Oil for these services. Certain expenditures of the Company are paid for by Kulczyk Oil on behalf of the Company and as at December 31, 2010 the Company owed $nil (2009 - $28,382) for these costs. During the year ended December 31, 2010 the Company reimbursed Kulczyk Oil for $18,743 of expenditures paid on behalf the Company.

Kulczyk Oil remains legally responsible for a guarantee issued in August 2007 ("the Loon Peru Guarantee") to the Government of Peru regarding the granting of the Block 127 license contract to Loon Peru Limited, a wholly-owned subsidiary of the Company. The Company has entered into an indemnification agreement with Kulczyk Oil in respect of the Loon Guarantee. The transfer of the Loon Peru Guarantee from Kulczyk Oil to the Company requires the formal approval of the Government of Peru which has not yet been obtained. The Company has fulfilled its work commitments under the first phase of the exploration program, and the Company and its operator announced on October 25, 2010 that the joint venture will not proceed to the second exploration phase. As a result, the Company believes there is no longer a material exposure to the guarantee.

The above related party transactions were at exchange amounts agreed to by both parties which approximate fair value.

Liquidity and Capital Resources

The Company is an oil and gas exploration and development company with properties principally located in Colombia. Of the Company's properties in Colombia, the Delta-1 well is in the development stage with two other wells in the exploration stage. The properties have no proved reserves at December 31, 2010. The Company does not generate production from operations to fund the continued exploration and development of all of the Company's oil and gas properties.

The consolidated financial statements have been prepared on a going concern basis, which contemplates the realization of assets and settlement of liabilities in the normal course of business and do not reflect adjustments that would otherwise be necessary if the going concern assumption was not valid. To date, the Company's exploration and development operations have been financed by way of equity issuances and by farm-out arrangements with third parties who pay for all or a portion of the Company's expenditures to earn a portion of the Company's ownership interests. The Company's cash and existing farm-out arrangements are not sufficient to fund the exploration and development program over the next twelve months. Additional equity or farm-out arrangements will be required to fund the exploration and development program and there are no guarantees that additional equity or farm-out arrangements will be available when needed.

Basis of Presentation

The consolidated financial statements of Loon Corp have been prepared by management in accordance with Canadian generally accepted accounting principles ("**GAAP**"). The Company uses the United States dollar as its measurement and reporting currency.

BOE Presentation

Production information is reported in units of barrels of oil equivalent ("**BOE**"). The BOE conversion ratio is based on an energy equivalency and all BOE conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet of gas to one barrel of oil.

Non-GAAP Measures

The financial information presented herein has been prepared in accordance with GAAP except for the term, "working capital" which is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP. The non-GAAP measure is presented for information purposes only and should not be considered an alternative to, or more meaningful than information presented in accordance with GAAP. Management believes that working capital may be a useful supplemental measure as it is used by the Company to evaluate the timing and amount of capital required to fund future operations. The Company's method of calculating this measure may differ from those of other companies and, accordingly, they may not be comparable to such measures used by other companies.

The Company calculates these non-GAAP measures as follows:

Working capital	Year ended December 31, 2010	2009
Current assets	$ 1,547,231	$ 2,033,248
Current liabilities	(759,446)	(759,937)
	$ 787,785	$ 1,273,311

Forward Looking Statements

This MD&A contains forward-looking statements. These statements relate to future events or future performance of the Company. When used in this MD&A, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "estimate", "predict", "seek", "propose", "expect", "potential", "continue", and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Company's current views with respect to certain events, and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Company's actual results, performance, or achievements to vary from those described in this MD&A. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, estimated, or expected. Specific forward-looking statements in this MD&A, among others, include statements pertaining to the following:

- factors upon which the Company will decide whether or not to undertake a specific course of action;
- world-wide supply and demand for petroleum products;
- expectations regarding the Company's ability to raise capital;
- treatment under governmental regulatory regimes; and
- commodity prices.

With respect to forward-looking statements in this MD&A, the Company has made assumptions, regarding, among other things:

- the impact of increasing competition;
- the ability of farm-out partners to satisfy their obligations;
- the Company's ability to obtain additional financing on satisfactory terms; and
- the Company's ability to attract and retain qualified personnel.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

- general economic conditions;
- volatility in global market prices for oil and natural gas;
- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- the availability of capital; and
- alternatives to and changing demand for petroleum products.

Furthermore, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future.

The forward–looking statements contained in this MD&A are expressly qualified in their entirety by this cautionary statement. These statements apply only as of the date of this MD&A.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates. Information regarding the accounting policies selected by the Company, and the critical accounting estimates used are set out in the notes to the Company's consolidated financial statements for the year ended December 31, 2010 and 2009, and are further discussed below.

The Company considers the following accounting estimate to be critical given the uncertainties that exist at the time the consolidated financial statements are prepared:

a) Cost recovery test on property and equipment

The Company performs a cost recovery test for each cost centre at least annually to evaluate and if appropriate, recognize impairment when the carrying value of property and equipment exceeds the undiscounted future cash flows from reserves using estimated future commodity prices. The amount of any impairment to be recognized is determined as the excess of the carrying value over fair value. Fair value is determined using proven and probable reserves together with undeveloped land, and is based on the present value of expected future cash flows discounted at a risk-free rate of interest. The Company also completes an analysis of the carrying value of undeveloped properties at least annually to ensure there are no indicators of impairment. These indicators would include, but are not limited to, results of seismic reprocessing and acquisition, licence expirations and management's determination that a project or property is no longer economically feasible.

Future Accounting Policies

International Financial Reporting Standards

Publicly accountable entities will be required to adopt International Financial Reporting Standards ("**IFRS**") for interim and annual financial statements for fiscal years beginning on or after January 1, 2011 including comparative figures for the prior year. The Company will be required to transition to IFRS effective January 1, 2011. The Company intends to issue its first interim financial statements under IFRS for the three month period ending March 31, 2011.

The following are the significant IFRS differences impacting the financial statements of the Company:

IFRS adoption election for oil and gas entities –management anticipates applying the IFRS 1 election whereby property, plant and equipment will be allocated to exploration and evaluation assets ("**E&E**") and development assets based on their carrying amount under Canadian GAAP as at January 1, 2010. The Company's Colombian assets will form two cash generating units under IFRS, one for each concession in the country. The only well with reserve assignments at January 1, 2010, the Delta-1 well is within the Buganviles Association Contract, therefore all of the Colombian full cost pool will be allocated to this well on conversion to IFRS. The Delta-1 well will be categorized as Property and equipment, whereas Visure-1X and Tuqueque-1X will initially be categorized as E&E. The Peruvian full cost pool will be considered an E&E asset upon conversion to IFRS and recorded at the same amount as under Canadian GAAP.

Property, plant and equipment– the carrying amount of Company's undeveloped properties is considered E&E assets under IFRS, whereas developed or producing properties will be classified as Property and equipment. IFRS permits an entity to elect the level at which E&E assets will be tested for impairment. E&E assets can be tested for impairment at a granular level or aggregated up to the level of an operating segment. Management has determined that E&E assets will be assessed for impairment at the cash generating unit related to the E&E assets. Management has also determined that Property and equipment will be assessed for impairment at the level of a cash generating unit, which will generally be at the level of a concession. Under Canadian GAAP, the Company assessed its undeveloped properties for impairment at the cost centre or country level. The carrying values of the Company's developed Colombian assets are tested for impairment under Canadian GAAP using a "ceiling test" or recoverable discounted cash flow analysis. Under IFRS, impairment of the Colombian cash generating units will be based on the recoverable amount, being the greater of fair value less costs to sell and value in use.

The Property and equipment currently held will be classified as Property and equipment under IFRS, with a possible opening balance sheet adjustment to reflect the fair value of the Delta-1 well. Any new expenditure incurred for Visure-1X and Tuqueque-1X will be classified as Exploration and evaluation assets.

Under IFRS, at January 1, 2010, the carrying value of the Colombian assets will be written down to their estimated fair value, which has not been finalized. Assets in Peru will be recorded at the same amount under Canadian GAAP and IFRS on January 1, 2010. Under IFRS, the impairment charge for Peru recorded under Canadian GAAP will not differ. Management is currently finalizing the estimated impairment of the Colombian cash generating unit as at January 1, 2010.

Asset retirement obligation - The Company recognizes the fair value of its asset retirement obligation as a liability at the time it incurs an obligation for the future abandonment and reclamation costs resulting from its resource operations. The asset retirement obligation is initially measured at its estimated fair value, which is the discounted future value of the liability, with the liability then accreting each subsequent period until the obligation is settled. The estimated fair value of the asset retirement obligation is capitalized to the petroleum and natural gas properties and equipment accounts, and is depleted over the estimated useful life of these assets. Under Canadian GAAP, the net present value of future cash outflows is discounted using the risk-adjusted rate of return. Upon conversion to IFRS, the net present value of future cash outflows is discounted using the risk free rate of return. The conversion to IFRS will result in an increase in the Asset retirement obligation of approximately $30,000 with a corresponding adjustment to retained earnings.

Internal Controls over Financial Reporting

The board of directors, through its Audit Committee, is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Audit Committee meets at least annually with the Company's external auditors to review accounting, internal control, financial reporting, and audit matters. Internal controls over financial reporting have not changed significantly since the last reporting period.

Approval

The Company's Board of Directors has approved the disclosure contained within this MD&A.

Additional Information

Additional information regarding the Company and its business and operations is available on the Company's profile at **www.sedar.com**. Copies of the information can also be obtained by contacting the Company at Loon Energy Corporation 1170, 700 – 4th Avenue S.W., Calgary, Alberta, T2P 3J4 (Phone: +1 403 264-8877) or by e-mail at **ryaniw@loonenergy.com**.