EAST WEST PETROLEUM CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE NINE MONTHS ENDED DECEMBER 31, 2015

This discussion and analysis of financial position and results of operation is prepared as at February 26, 2016 and should be read in conjunction with the unaudited condensed consolidated interim financial statements for the nine months ended December 31, 2015 of East West Petroleum Corp. ("East West" or the "Company"). The following disclosure and associated financial statements are presented in accordance with International Financial Reporting Standards ("IFRS"). Except as otherwise disclosed, all dollar figures included therein and in the following management discussion and analysis ("MD&A") are quoted in Canadian dollars. Additional information relevant to the Company's activities, can be found on SEDAR at www.sedar.com .

Forward-Looking Statements

Forward-looking information is subject to known and unknown risks, uncertainties and other factors that may cause the Company's actual results, level of activity, performance or achievements to be materially different from those expressed or implied by such forward-looking information. Such factors include, but are not limited to: the ability to raise sufficient capital to fund exploration and development; the quantity of and future net revenues from the Company's reserves; oil and natural gas production levels; commodity prices, foreign currency exchange rates and interest rates; capital expenditure programs and other expenditures; supply and demand for oil and natural gas; schedules and timing of certain projects and the Company's strategy for growth; competitive conditions; the Company's future operating and financial results; and treatment under governmental and other regulatory regimes and tax, environmental and other laws.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. Best estimate resources are considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean). As estimates, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources that the estimated reserves or resources will be recovered or produced.

This list is not exhaustive of the factors that may affect our forward-looking information. These and other factors should be considered carefully and readers should not place undue reliance on such forward-looking information. The Company disclaims any intention or obligation to update or revise forward-looking information, whether as a result of new information, future events or otherwise.

All of the Company's public disclosure filings, including its most recent management information circular, material change reports, press releases and other information, may be accessed via www.sedar.com and readers are urged to review these materials, including the reserve reports filed with respect to the Company's petroleum and natural gas properties.

Company Overview

The Company is a reporting issuer in British Columbia and Alberta and trades on the TSX Venture Exchange ("TSXV") under the symbol "EW" as a Tier 1 issuer. The Company carries on business in one operating segment, being the acquisition of, exploration for and production from petroleum and natural gas properties. The Company's current portfolio consists of interests in exploration concessions in New Zealand and Romania and producing properties in the Taranaki Basin, New Zealand and Alberta, Canada. The Company is not the operator of any of its petroleum and gas interest and is currently focussed participating on activities on the exploration, evaluation and development of its petroleum interests in the Taranaki Basin, New Zealand. The Company's principal office is located at #1210 - 1095 West Pender Street, Vancouver, BC, V6E 2M6.

Normal Course Issuer Bid

The Company had filed a renewal normal course issuer bid ("NCIB") which authorized the Company to repurchase for cancellation up to 8,725,822 common shares until February 2, 2016 or the date by which the Company has acquired the maximum number of common shares under the normal course issuer bid. The Company repurchased 1,326,500 common shares under this NCIB for $142,908.

On February 3, 2016 the Company filed a renewal NCIB which authorizes the Company to repurchase for cancellation up to 8,507,552 common shares until February 2, 2017 or the date by which the Company has acquired the maximum number of common shares under the normal course issuer bid. The purchases are to be made through the facilities of the TSXV during the period February 3, 2016 to February 2, 2017. As of the date of this MD&A, the Company has not repurchased common shares under this renewal NCIB. See also "Selected Financial Data - Results of Operations" and "Outstanding Share Data".

Projects Update

In this MD&A, production and reserves information may be presented on a barrel of oil equivalent ("BOE") basis with six thousand cubic feet ("MCF") of natural gas being equivalent to one barrel ("bbl") of crude oil or natural gas liquids. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

New Zealand

The Company has active drilling, testing and production operations in the Taranaki Basin of New Zealand. All licenses are operated by the Company's partner, TAG, and all wells are targeting shallow Miocene targets in the Urenui and Mt. Messenger formations which have been shown to be productive for oil and gas throughout the Basin, including on TAG's adjacent Cheal field.

Within the Taranaki Basin, East West holds the following working interests:

PEP 54877 (Cheal North East) - East West 30%

The initial permit work at the Cheal E-Site located on PEP 54877 included the drilling of five exploration wells (Cheal-E1, E2, E3, E4 and E5) which were successfully completed in mid-December 2013. The Cheal-E1 well was placed onto production in November 2013, followed during the first quarter of calendar 2014 by two Cheal E-Site wells capable of production (Cheal-E4 and E5).

In May 2015 the Company was informed by TAG that the TAG owned Cheal E to A pipeline was completed and operational, giving the Company the ability to monetize future oil and gas wells drilled in the Cheal-E development area, sell previously flared gas generating additional revenues and lowering operating costs through facility optimizations.

Petroleum production from Cheal North East averaged 168 net BOE's per day (57% oil) in Q3 compared to an average of 229 BOE's per day (62% oil) in Q2. The decrease of 61 net BOE's per day from Q2 is due to the E6 well being offline due to downhole mechanical issues and to natural field decline rates.

PEP 54879 (Cheal South) - East West 50%

The initial permit work for PEP 54879 included drilling three exploration wells, the Cheal-G1, G2 and G3. A 15-day flow test was completed on the Cheal-G1 well which produced 1,016 barrels of oil. The test oil was subsequently sold for net proceeds of $44,972 and all net revenues have been recorded as a recovery against the capitalized costs. The G1 well has the potential to be full-time producing and suitable economic methods are under review which would enable the G1 well to produce on a full time basis.

Reserves Data

An independent reserves evaluation, relating to the resource base of the Company in the Cheal Area of New Zealand, effective March 31, 2015, has been prepared by Sproule International Limited. The report follows all industry standard procedures and is in conformity with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 ("NI 51-101"). Readers are encouraged to review the Form 51-101 F1 - *Statement of Reserve Data and Other Oil and Gas Information*, which is a Summary of the report, filed on the SEDAR website at www.sedar.com.

Canada

Effective September 1, 2010 the Company executed a purchase and sale agreement with Sphere Energy Corp. ("Sphere"), a private company, whereby the Company acquired Sphere's working interests, ranging from 4.1125% to 20%, in four oil wells and fourteen gas wells (eight flowing coal bed methane ("CBM") gas) (the "Carbon Property") located approximately 50 miles northeast of Calgary, Alberta. The wells are producing from the Horseshoe Canyon, Basal Belly River, Belly River, Viking and Glauconitic formations.

The Carbon Property is located approximately fifty miles northeast of Calgary, Alberta in Township 29, Range 22W4M. The Company holds interests ranging from 4.1125% to 20% in three producing oil wells and twelve gas wells. The wells are producing from the Horseshoe Canyon, Basal Belly River, Belly River, Viking, Glauconitic, and Ellerslie Formations. Approximately 86% of the proved plus probable value discounted at 10% of this property lies in three oilwells: 02/11-13-029-22W4/0; 00/04-13-029-22W4/0; and 00/06-13-029-22W4/0.

As of the date of this MD&A, the Carbon Property is not considered to be a material property of the Company.

Romania

During fiscal 2010 the Company was informed by the government of Romania that it had been awarded four exploration blocks located in the Pannonian Basin, in western Romania. In May 2011 the Company signed petroleum concession agreements with the National Agency for Minerals and Hydrocarbons ("NAMR") the government agency in Romania which regulates the oil and gas industry.

The four concessions have specific mandatory work programs (the "Romania Work Programs"), which were estimated at US $56,630,000 for all four programs, to be completed over two years from final approval. Production from the concessions is also subject to royalties ranging from 3.5% to 13.5% based on quarterly gross production payable to the government.

On May 20, 2011 the Company and Naftna Industrija Srbije j.s.c. Novi Sad ("NIS"), an arm's length corporation, signed a memorandum of understanding to jointly explore the four exploration blocks in Romania. On October 27, 2011 the Company and NIS signed a farm-out agreement (the "Farm-out"). Under the terms of the Farm-out, NIS paid the Company $250,000 and agreed to pay a further $275,000 upon final concession approvals by the government of Romania and assignment of an 85% participation interest and operatorship of the Romania Work Programs to NIS. NIS has the obligation to fund the Romania Work Programs, including environmental work, 2D and 3D seismic acquisition and processing, and the drilling of 12 wells. The Company retains a 15% carried interest in each block through the obligatory two year Phase I work program and the optional one year Phase II work program. If a commercial discovery is made, the Company is responsible for its 15% interest in development of the commercial discovery.

During fiscal 2012 the Company received final concession approval by the government of Romania for one exploration block (EX-2 Tria) and the Company transferred the 85% participation interest in EX-2 Tria to NIS Petrol S.R.L ("NSI Petrol"), a wholly-owned subsidiary of NIS, and the Company received a pro-rated payment of $68,750 from NIS. On November 22, 2013 the Company received final concession approval on the three remaining exploration blocks. The Company subsequently transferred the 85% participation interest in the exploration blocks to NIS Petrol and received the final payment of $206,250 during fiscal 2014.

NAMR has granted NIS and the Company an extension of 2.5 years, until June 2017, to conduct the Phase I work program for the exploration block, EX-2 Tria.

United States

On August 29, 2012 the Company entered into a Letter of Intent with Lani LLC ("Lani") to carry out a joint exploration program in the San Joaquin Basin of California, USA. At the time of the agreement, Lani, a private E&P company based in Ventura, California, held an exploration acreage position of approximately 4,500 gross acres in the southern region of the basin with a number of prospects and leads identified. Under the terms of the agreement, the Company indicated it would assume a 21.25% - 50% net participation interest in Lani's acreage position through a total of US $2,500,000 contribution to drill two exploration wells and for the acquisition of additional leases.

On November 13, 2012 the Company entered into a farm-in agreement, which superseded the August 29, 2012 Letter of Intent, and area of mutual interest agreement ("AMI") with Lani to carry out joint exploration programs in the San Joaquin Basin. The agreement provided the Company with participation interests in approximately 4,500 gross (3,200 net) acres in two prospective areas named Tejon Extension and Tejon Main, holding a 25% participation interest in the Tejon Extension leases and a 21.25% participation interest in Tejon Main leases.

On August 1, 2013 the Company entered into a Sales and Purchase Agreement with Solimar Energy, LLC whereby 28.75% participation interest was purchased in leases making up the Tejon Main area, bringing the Company's interest to 50%. The cost to the Company was US $110,000.

In December 2012 the Company and its partner NAMG spud the Lani 77-20 exploratory well on the Tejon Extension leases. The well flowed oil to the surface in uncommercial quantities and has been suspended pending additional studies. The Company has funded the required US $1,300,000 to earn its 25% participation interest in the Tejon Extension leases. The 77-20 well was suspended with further petrophysical analysis underway to determine the hydrocarbon of the shallower section in the well. Following analysis and consideration of prospects for further testing, East West determined that this well was unlikely to be commercial and the costs associated with the 77-20 well were provided for in fiscal 2014.

NAMG is the operator of the subject leases. As of the date of this MD&A, NAMG has been unsuccessful in obtaining sufficient financing to proceed with further exploration and development of the properties. In light of this uncertainty and results to date, the Company made a full impairment charge in fiscal 2015 on the remaining Tejon Main Area and White Wolf leases.

India

In March 2011 the Company was notified by the Directorate General of Hydrocarbons of India ("DGH") it was a successful bidder for an exploration block in the New Exploration Licensing Policy ("NELP") IX competitive bid round. The block lies in the Assam-Arakan Basin of northeast India. The DGH had announced the winning bids on a provisional basis, subject to final administrative review.

The acquired block, AA-ONN-2010/2, was awarded to a consortium consisting of Oil India Ltd. ("OIL"), (Operator, 40%), Oil and Natural Gas Corporation of India ("ONGC") (30%), Gas Authority of India Ltd. ("GAIL") (20%) and East West (10%). The primary term of this exploration production sharing contract is five years.

On March 28, 2012 the Company, along with its partners, received final approvals and signed the AA-ONN-2010/2 PSC agreement with the DGH at an official signing ceremony in New Delhi. Block AA-ONN-2010/2 covers approximately 395 sq. km. within the Karbi Anglong District of the Assam-Arakan Basin, a proven petroliferous region which covers more than 116,000 sq. km. in north-eastern India. The work program bid for the block consists of the drilling of two wells and the acquisition of about 400 sq. km. of 3D seismic data. In January 2015 the Petroleum Exploration License deed of agreement for Block AA-ONN-2010/2 was signed between the partners and the Government of Assam. In July 2015 the Company provided notice that it would be withdrawing from the PSC.

Investment in Associated Company

North South Petroleum Corp. ("North South")

On April 9, 2015 the Company, pursuant to a non-brokered private placement, acquired ownership and control over 3,900,000 common shares (the "North South Shares") for $195,000. With this initial purchase the Company owned 16.74% of the issued and outstanding common shares of North South.

On the acquisition of the North South Shares, Mr. David Sidoo, the President and CEO of the Company, was appointed as a director of North South. On May 22, 2015, the Honorable Herb Dhaliwal, a director of the Company, was also appointed as a director of North South. During the nine months ended December 31, 2015 the Company acquired a further 542,500 common shares of North South through open market purchases for a total consideration of $113,083 and as at December 31, 2015 the Company owned approximately 19% of the issued and outstanding common shares of North South. The Company's judgment is that it has significant influence over North South and, accordingly accounts for the investment under the equity method.

Subsequent to December 31, 2015 the Company has purchased an additional 84,000 common shares of North South through the public market for a total consideration of $15,960.

Selected Financial Data

The following selected financial information is derived from the unaudited condensed consolidated interim financial statements of the Company prepared in accordance with IFRS.

	Fiscal 2016			Fiscal 2015				Fiscal 2014
	Dec. 31 2015 $	Sep. 30 2015 $	Jun. 30 2015 $	Mar. 31 2015 $	Dec. 31 2014 $	Sep. 30 2014 $	Jun. 30 2014 $	Mar. 31 2014 $
Operations:								
Revenues, net of costs	210,059	525,232	633,133	747,049	899,935	1,371,347	1,164,082	3,136,475
Expenses	(1,096,794)	(1,430,337)	(1,244,022)	(3,681,902)	(2,441,979)	(1,272,702)	(3,703,911)	(5,707,656)
Other items	143,572	309,046	40,980	1,140,999	(132,379)	204,035	(854,009)	(3,025,455)
(Loss) income before deferred income tax	(743,163)	(596,059)	(569,909)	(1,793,854)	(1,674,423)	302,680	(3,393,838)	(5,596,636)
Deferred income tax	Nil	Nil	Nil	Nil	Nil	Nil	(25,000)	(210,000)
Net income (loss)	(743,163)	(596,059)	(569,909)	(1,793,854)	(1,674,423)	302,680	(3,418,838)	(5,806,636)
Other comprehensive income (loss), net	747,479	1,282	(1,032,994)	(360,051)	667,968	(1,187,515)	166,978	(626,442)
Comprehensive (loss) income	4,316	(594,777)	(1,602,903)	(2,153,905)	(1,006,455)	(884,835)	(3,251,860)	(6,433,078)
Basic and diluted (loss) income per share	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	0.01	(0.03)	(0.07)
Dividends per share	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Balance Sheet:								
Working capital	8,398,762	8,614,985	8,708,868	8,901,697	8,591,136	9,362,466	8,745,415	10,966,215
Total assets	17,231,425	17,229,246	17,925,164	19,539,844	21,794,694	22,510,465	23,426,418	29,682,150
Decommissioning liabilities	(1,198,604)	(1,057,191)	(977,938)	(1,062,292)	(952,108)	(886,520)	(983,377)	(995,388)

Results of Operations

Three Months Ended December 31, 2015 Compared to Three Months Ended September 30, 2015

Revenues and operating costs for the three months ended December 31, 2015 ("Q3") compared to the three months ended September 30, 2015 ("Q2") are as follows:

	Q3	Q2
Total sales	$ 670,695	$ 964,039
Total volume	18,650 BOE	21,346 BOE
Average realized price per BOE	$ 35.96	$ 45.16
Petroleum sales	$ 479,082	$ 748,378
Petroleum volume	12,292 BOE	13,833 BOE
Average petroleum realized price per BOE	$ 38.98	$ 54.10
Natural gas sales	$ 191,613	$ 215,661
Natural gas volume	6,358 BOE	7,513 BOE
Average natural gas realized price per BOE	$ 30.14	$ 28.71
Production costs	$ 393,274	$ 324,003
Average per BOE	$ 21.09	$ 15.18

	Q3	Q2
Transportation and storage costs	$ 95,253	$ 130,960
Average per BOE	$ 5.11	$ 6.14
Royalties	$ 26,733	$ 38,468
Average per BOE	$ 1.43	$ 1.80
Netback	$ 210,059	$ 470,608
Average per BOE	$ 11.26	$ 22.05

Petroleum and natural gas revenues decreased from $964,039 in Q2 to $670,695 in Q3, a decline of 30% due to a 13% decline in production volumes and a 20% decline in the averaged realized sales price. The average realized sales price decline was primarily driven by the general decline in oil prices over the quarter and a decrease in the proportion of natural gas being sold.

Total sales volumes decreased to 18,650 BOE in Q3 compared to 21,346 BOE in Q2. The 2,696 BOE decrease in sales in Q3 was primarily a result of the impact of the E6 well being taken offline and shut-in during the quarter while it awaits servicing. In May 2015 the Cheal E to A pipeline was completed and operational. See "Projects Update - New Zealand". Accordingly, gas production contributed 6,358 BOE (44,754 GJ) in Q3 compared to 7,513 BOE (52,879 GJ) in Q2.

Production costs in Q3 compared to Q2 on a per BOE basis increased from $15.18 per BOE in Q2 to $21.09 per BOE in Q3. The increase was attributed to the fixed nature of operating costs being spread over lower production volumes.

Transportation and storage costs decreased, both in total and on a BOE basis, due to the commissioning of the pipeline, which is being used to transport both gas and oil thus reducing transportation costs.

As a result of reduced commodity prices and lower production volumes, royalties declined to $26,733 in Q3 from $38,468 in Q2.

Nine Months Ended December 31, 2015 Compared to Nine Months Ended December 31, 2014

Revenues and operating costs for the nine months ended December 31, 2015 (the "2015 period") compared to the nine months ended December 31, 2014 (the "2014 period") are as follows:

	2015 Period	2014 Period
Total sales	$ 2,824,132	$ 5,282,713
Total volume	62,172 BOE	55,910 BOE
Average realized price per BOE	$ 45.42	$ 94.49
Petroleum sales	$ 2,314,928	$ 5,282,713
Petroleum volume	44,848 BOE	55,910 BOE
Average petroleum realized price per BOE	$ 51.62	$ 94.49
Natural gas sales	$ 509,204	-
Natural gas volume	17,324 BOE	-
Average natural gas realized price per BOE	$ 29.39	-
Production costs	$ 1,032,583	$ 898,020
Average per BOE	$ 16.61	$ 16.06
Transportation and storage costs	$ 416,016	$ 694,497
Average per BOE	$ 6.69	$ 12.42
Royalties	$ 116,357	$ 236,832
Average per BOE	$ 1.87	$ 4.24
Netback	$ 1,259,176	$ 3,453,364
Average per BOE	$ 20.25	$ 61.77

Petroleum and natural gas revenues decreased from $5,282,713 in the 2014 period to $2,824,132 in the 2015 period, a decline of 47% primarily due to lower crude oil prices and lower production volumes of crude oil. The decrease in revenues was partially offset by the commencement of gas production and foreign exchange gains. Oil sales volumes declined approximately 20% while average realized sales prices for crude oil declined approximately 56% from the 2014 period to the 2015 period. Total sales volumes increased to 62,172 BOE in the 2015 period compared to 55,910 BOE in the 2014 period. The 6,262 BOE increase in sales in the 2015 period was primarily a result of the commencement of natural gas sales, which had previously been flared, following the commissioning of the pipeline. Gas production contributed 17,324 BOE (121,939 GJ) in the 2015 period. During the 2014 period natural gas production was flared and, accordingly, no revenue was generated.

Production costs in the 2015 period compared to the 2014 period on a per BOE basis increased from $16.06 per BOE in the 2014 period to $16.66 per BOE in the 2015 period. The increase was primarily due to additional maintenance at the Cheal-E site.

Transportation and storage costs decreased, both in total and on a BOE basis, due to the commissioning of the pipeline, which is being used to transport both gas and oil thus reducing transportation costs.

As a result of reduced commodity prices, royalties declined to $116,357 in the 2015 period from $236,832 in the 2014 period.

During the nine months ended December 31, 2015 (the “2015 period”) the Company reported a net loss of $1,909,131 ($0.02 per share) compared to a net loss of $4,790,851 ($0.05 per share) during the nine months ended December 31, 2014 (the “2014 period”), a decrease in loss of $2,881,720. The overall decrease in loss during the 2015 period was attributed to the following:

(i) a decrease in general exploration expenses of $2,531,480, from $2,833,171 in the 2014 period, mainly for costs incurred on PEP 54876, compared to $301,691 in the 2015 period;
(ii) the recognition of a foreign exchange gain of $517,622 in the 2015 period compared to a foreign exchange loss of $511,457 in the 2014 period, a change of $1,029,079; and
(iii) partially offset by a decrease in net revenue of $2,458,581, from $5,282,713 in the 2014 period to $2,824,132 in 2015 period as a result of the significant impact of lower petroleum prices.

General and administrative expenses incurred during the 2015 period and 2014 period are as follows:

	2015 **$**	**2014** **$**
Accounting and administrative	48,900	52,135
Audit and related	66,217	77,516
Bank charges and letter of credit fees	3,751	57,445
Corporate development	24,266	27,582
Legal	69,840	30,386
Office	44,882	28,009
Other (recovery)	-	(16,533)
Professional fees	468,602	651,385
Regulatory fees	6,179	11,429
Rent	51,842	51,309
Salaries and benefits	91,664	32,231
Shareholder costs	10,059	3,899
Telephone	7,408	8,331
Transfer agent fees	6,402	5,344
Travel	144,763	185,634
	1,044,775	1,206,102

Specific expenses of note for the 2015 period and 2014 period are as follows:

(i) professional fees totalling $468,602 were incurred in the 2015 period compared to $651,385 in the 2014 period as follows:

- $384,000 was paid to directors and officers of the Company in the 2015 period, a decrease of $131,000 from $515,000 in the 2014 period. The decrease was due to an overall voluntary reduction in compensation agreed to by the Board members. See also “Related Party Transactions”;
- $51,000 was paid to consultants for administrative consulting in the 2015 period compared to $96,000 in the 2014 period, reflecting the employment of an individual in October 2014, whereas in the 2014 period the person was contracted as a consultant. Accordingly, during the 2015 period the Company recorded $91,664 (2014 - $32,231) for salaries and benefits attributed to the individual; and
- $33,602 was paid in the 2015 period to consultants for financial consulting services provided and is comparable to the $40,385 paid in the 2014 period;

(ii) legal fees of $69,840 were incurred in the 2015 period, an increase of $39,454 from $30,386 in the 2014 period, reflecting increase legal services provided for the property bidding process in Mexico;

(iii) bank charges of $3,751 (2014 - $57,445) were incurred by the Company. During the 2014 period the Company incurred significant bank fees on the release of a guarantee; and

(iv) during the 2014 period the Company recorded a credit of $16,533 for a rent deposit forfeited by Ava Resources Corp. for previously shared office premises.

During the 2015 period the Company recorded general exploration expenses of $301,691 (2014 - $2,833,171) of which $37,165 (2014 - $2,678,057) was for the drilling and abandonment of PEP 54876 and $264,526 (2014 - $155,114) was for ongoing review of current and potential exploration and evaluation assets.

During the 2015 period the Company recorded share-based compensation expense of $11,200 (2014 - $653,525) on the granting and vesting of share options. In addition the Company recorded share-based compensation expense of $20,140 (2014 - $67,582) on the re-pricing of share options which had previously been granted. The Company also recorded a compensation recovery of $11,902 on the reversal of prior year’s compensation expense previously recorded on forfeited unvested share options.

Interest income is generated from cash on deposit with a senior financial institution and short-term money market instrument issued by major financial institutions. During the 2015 period the Company reported interest income of $50,976, a decrease of $39,536, compared to $90,512 for the 2014 period. The decrease in interest income in the 2015 period was due to lower levels of cash compared to the 2014 period and lower yields obtained during the 2015 period.

During the 2015 period the Company repurchased 1,018,500 (2014 - 1,681,000) common shares for $108,338 (2014 - $282,731). See also “Normal Course Issuer Bid”.

Exploration and Evaluation Assets

	New Zealand		United States		
	PEP 54879 $	PEP 55770 $	Tejon Main Area $	White Wolf $	Total $
Balance at March 31, 2014	5,666,415	-	122,154	318,121	6,106,690
Capital expenditures	289,744	63,357	-	-	353,101
Net revenues pre-commercial discovery	(44,972)	-	-	-	(44,972)
Revision of estimate for decommissioning liabilities	(8,134)	-	-	-	(8,134)
Foreign exchange movement	(67,941)	-	-	-	(67,941)
Impairment	-	(63,357)	(122,154)	(318,121)	(503,632)
Balance at March 31, 2015	5,835,112	-	-	-	5,835,112
Capital expenditures	55,086	-	-	-	55,086
Revision of estimate for decommissioning liabilities	6,374	-	-	-	6,374
Foreign exchange movement	35,649	-	-	-	35,649
Balance at December 31, 2015	5,932,221	-	-	-	5,932,221

During the 2015 period the Company incurred additions of $55,086 (2014 - $716,891) for exploration and evaluation assets. Details of the Company’s activities are discussed in “Projects Update”. During the 2014 period the Company received net revenues of $37,048 from production from the testing of the G1 well on PEP 54879. In addition during the 2014 period the Company recorded an impairment of $503,359 on its exploration and evaluation assets.

Property, Plant and Equipment

During the 2015 period the Company spent $341,136 (2014 - $714,077) for property, plant and equipment expenditures on PEP 54877. The Company also recorded a further debit of $78,989 (2014 - credit of $52,735) to decommissioning estimates and an increase of $85,916 (2014 - $442,492) for the impact of foreign exchange translation.

Financial Condition / Capital Resources

As at December 31, 2015 the Company had cash resources of $7,984,666, a decrease of $416,456 from $8,401,122 as at March 31, 2015. Operating activities during the 2015 period was positive generating cash of $608,760. Investing activities used $447,356 cash, $139,273 for capital and exploration expenditures and $308,083 for purchase of common shares of North South. The Company also spent $108,338 for the ongoing purchase of its common shares under the NCIB.

As at December 31, 2015 the Company had working capital of $8,398,762. The Company is currently focussing on the exploration, development and production of oil and gas from its Cheal properties. The Company believes that it currently has sufficient financial resources to conduct anticipated exploration and development programs and meet anticipated corporate administration costs for the upcoming twelve month period. However, exploration activities may change due to ongoing results and recommendations, discoveries may require appraisal and development work or the Company may acquire additional properties, which may entail significant funding or exploration commitments. In the event that the occasion arises, the Company may be required to obtain additional financing. The Company has relied solely on equity financing to raise the requisite financial resources. While it has been successful in the past, there can be no assurance that the Company will be successful in raising future financing should the need arise.

Contractual Commitments

	Total $	**Less than One Year $**	**More than One Year $**
Operating leases	40,320	40,320	-
Other long-term obligations	7,056,000	2,218,000	4,838,000
Total contractual obligations	7,096,320	2,258,320	4,838,000

Effective August 1, 2011 the Company entered into an operating lease, expiring July 31, 2016, for the rental of an office in Vancouver, BC with a gross monthly lease payment of $5,760.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements.

Proposed Transactions

The Company does not have any proposed transactions.

Critical Accounting Estimates

The preparation of financial statements in conformity IFRS 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 revenues and expenditures during the reporting period. Examples of significant estimates made by management include the determination of mineralized reserves, plant and equipment lives, estimating the fair values of financial instruments, impairment of long-lived assets, reclamation and rehabilitation provisions, valuation allowances for future income tax assets and assumptions used for share-based compensation. Actual results may differ from those estimates.

Changes in Accounting Policies

There are no changes in accounting policies.

Related Party Disclosures

A number of key management personnel, or their related parties, hold positions in other entities that result in them having control or significant influence over the financial or operating policies of those entities. Certain of these entities transacted with the Company during the reporting period.

(a) *Transactions with Key Management Personnel*

During the 2015 period and 2014 period the following amounts were incurred with respect to Mr. David Sidoo, the Company's President and Chief Executive Officer ("CEO") and Mr. Nick DeMare, the Company's Chief Financial Officer ("CFO"):

	2015 **$**	**2014** **$**
Professional fees - David Sidoo (1)	108,000	150,500
Professional fees - Nick DeMare (2)	31,500	41,500
Share-based compensation - David Sidoo	-	199,415
Share-based compensation - Nick DeMare	-	137,427
	139,500	528,842

(1) Paid to Siden Investments Ltd., a private company owned by Mr. Sidoo.
(2) Paid to Chase Management Ltd. ("Chase") a private company owned by Mr. DeMare.

As at December 31, 2015, $nil (2014 - $28,500) remained unpaid.

(b) *Transactions with Other Related Parties*

(i) During the 2015 period and 2014 period the following amounts were incurred with respect to non-executive officers and directors of the Company:

	2015 **$**	**2014** **$**
Professional fees - Marc Bustin, Director (1)	216,000	262,000
Professional fees - Herb Dhaliwal, Director (2)	28,500	61,000
Share-based compensation - Marc Bustin, Director	-	136,645
Share-based compensation - Herb Dhaliwal, Director	-	136,522
	244,500	596,167

(1) Paid to RMB Earth Science Service Consulting Ltd., a private company owned by Mr. Bustin.
(2) Paid to ADH Holdings Ltd., a private company owned by Mr. Dhaliwal.

As at December 31, 2015, $38,000 (2014 - $48,000) remained unpaid.

(ii) During the 2015 period the Company incurred a total of $48,900 (2014 - $50,150) to Chase for accounting and administration services provided by Chase personnel, excluding Mr. DeMare. As at December 31, 2015, $7,500 (2014 - $11,250) remained unpaid.

(c) On March 6, 2015 the Company entered into a letter of intent (the "LOI") with Frontier Natural Resources Inc. ("Frontier") whereby it provided Frontier a credit facility of US $250,000 (the "Credit Facility"). The advances under the Credit Facility bear interest at 3% per annum. The Company also has the option to convert the advances into Class A Preferred Shares of Frontier at a conversion price of US $0.20 per share.

During the nine months ended December 31, 2015 the Company recorded interest income of $7,066 (2015 - $nil). As at December 31, 2015, $1,738 of interest remained unpaid.

On December 31, 2015 the advances became due and payable. Frontier is currently working towards a financing which will enable repayment of the advances and accrued interest.

Frontier is a privately held oil and natural gas company incorporated in Pennsylvania, U.S.A. Mr. Bustin, a director of the Company, is also a shareholder and director of Frontier.

(d) The Company has made significant investments in North South. See "Investment in Associated Company".

Financial Instruments and Risk Management

The nature of the Company's operations expose the Company to credit risk, liquidity risk and market risk, and changes in commodity prices, foreign exchange rates and interest rates may have a material effect on cash flows, net income and comprehensive income.

This note provides information about the Company's exposure to each of the above risks as well as the Company's objectives, policies and processes for measuring and managing these risks.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and to monitor market conditions and the Company's activities. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and policies.

Credit Risk

Credit risk is the risk of financial loss to the Company if counterparties do not fulfill their contractual obligations. The most significant exposure to this risk is relative to the sale of oil production. All of the Company's production is sold directly to a major oil company. The Company is paid for its oil sales within 30 days of shipment. The Company has assessed the risk of non-collection from the buyer as low due to the buyer's financial condition.

Cash is held with a Canadian chartered bank and is monitored to ensure a stable return.

The carrying amount of cash, amounts receivable and advances receivable represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts on its amounts receivable as at December 31, 2015 and did not provide for any doubtful accounts.

Commodity Price Risk

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices, affecting results of operations and cash generated from operating activities. Such prices may also affect the value of exploration and development properties and the level of spending for future activities. Prices received by the Company for its production are largely beyond the Company's control as petroleum prices are impacted by world economic events that dictate the levels of supply and demand. All of the Company's oil production is sold at spot rates exposing the Company to the risk of price movements. Effective May 16, 2015 the Company entered into a gas supply agreement to sell its share of gas production from the Cheal E field at a price of NZD $4.75 per gigajoule, ending December 31, 2016.

Liquidity Risk

Liquidity risk is the risk that the Company will not have the resources to meet its obligations as they fall due. The Company manages this risk by closely monitoring cash forecasts and managing resources to ensure that it will have sufficient liquidity to meet its obligations. All of the Company's financial liabilities are classified as current and are anticipated to mature within the next fiscal period.

Market Risk

Market risk is the risk that changes in foreign exchange rates, commodity prices and interest rates will affect the Company's cash flows, net income and comprehensive income. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

Foreign Currency Exchange Rate Risk

Foreign currency exchange rate risk is the risk that future cash flows, net income and comprehensive income will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum sales are denominated in United States dollars and gas sales, operational and capital activities related to the Company's properties are transacted primarily in New Zealand dollars and/or United States dollars with some costs also being incurred in Canadian dollars.

The Company currently does not have significant exposure to other currencies and this is not expected to change in the foreseeable future as the work commitments in New Zealand are expected to be carried out in New Zealand and to a lesser extent, in United States dollars.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its cash which bears a floating rate of interest. The risk is not considered significant.

The Company did not have any interest rate swaps or financial contracts in place during the nine months ended December 31, 2015 or 2014 and any variations in interest rates would not have materially affected net income.

Fair Value of Financial Instruments

Financial instruments are classified into one of the following five categories: fair value through profit or loss ("FVTPL"); held-to-maturity investments; loans and receivables; available-for-sale and other financial liabilities.

The Company's financial instruments recorded at fair value require disclosure about how the fair value was determined based on significant levels of inputs described in the following hierarchy:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and value to provide pricing information on an ongoing basis.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

Level 3 - Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The recorded amounts for amounts receivable, advances receivable and accounts payable and accrued liabilities approximate their fair value due to their short-term nature. The fair value of cash and investment under the fair value hierarchy is measured using Level 1 inputs.

Risks and Uncertainties

The Company is engaged in the exploration for and development of oil and natural gas properties. These activities involve significant risks which careful evaluation, experience and knowledge may not eliminate in some cases. The commercial viability of any petroleum and natural gas properties depends on many factors not all of which are within the control of management. Operationally the Company faces risks that are associated with and affect the financial viability of a given petroleum and natural gas property. These include risks associated with finding, developing and producing these petroleum and natural gas reserves. In addition, Government regulations, taxes, royalties, land tenure, land use, environmental protection and reclamation and closure obligations, have an impact on the economic viability of a petroleum and natural gas property.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 expenses during the reporting period. Actual results could differ from those estimates.

The Company's ability to continue its operations and to realize assets at their carrying values is dependent upon the continued support of its shareholders, obtaining additional financing and generating revenues sufficient to cover its operating costs. The accompanying financial statements do not give effect to any adjustments which would be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and discharge its liabilities in other than the normal course of business and at amounts different from those reflected in the accompanying audited financial statements.

Any forward-looking information in the MD&A is based on the conclusions of management. The Company cautions that due to risks and uncertainties, actual events may differ materially from current expectations. With respect to the Company's operations, actual events may differ from current expectations due to economic conditions, new opportunities, changing budget priorities of the company and other factors.

Outstanding Share Data

The Company's authorized share capital is unlimited common shares with no par value. As at February 26, 2016, there were 89,585,665 outstanding common shares (net of shares repurchased) and 6,013,000 share options outstanding with exercise prices ranging from $0.14 to $0.50 per share.