EAST WEST PETROLEUM CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED MARCH 31, 2015

This discussion and analysis of financial position and results of operation is prepared as at July 28, 2015 and should be read in conjunction with the audited consolidated financial statements for the twelve months ended March 31, 2015 ("fiscal 2015") and the fifteen months ended March 31, 2014 ("fiscal 2014") of East West Petroleum Corp. ("East West" or the "Company"). The Company changed its fiscal year end from December 31 to March 31 effective March 31, 2014. Accordingly, the results shown are not fully comparable. See also "Change in Fiscal Year-End". 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 was incorporated on October 23, 1987 under the provisions of the Company Act (British Columbia). During fiscal 2010 the Company negotiated the acquisition of interests in petroleum and natural gas properties, and conducted a number of private placement financings. As a result, effective October 1, 2010, the Company's listing of its common shares was transferred from the NEX Board ("NEX") to the TSX Venture Exchange ("TSXV") as a Tier 2 oil and gas issuer trading under the symbol "EW". Effective December 30, 2014 the Company, having met the requirements for a Tier 1 company, was upgraded to a Tier 1 oil and gas 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. During the last year oil prices have decreased significantly, which has reduced profitability and impacted operating cash flows. Subsequently, the Company's partner, TAG Oil Ltd. ("TAG"), the operator of the Cheal field, has taken steps to increase efficiency and lower production and administration costs wherever possible over the next twelve months.

The Company's principal office is located at #1210 - 1095 West Pender Street, Vancouver, BC, V6E 2M6.

Change in Fiscal Year-End

Effective March 31, 2014 the Company changed its fiscal year end from December 31 to March 31. The change in the fiscal year was made for the purpose of streamlining the Company's financial reporting. The consolidated financial statements and this MD&A are presented for a period of twelve months ended March 31, 2015 compared to fifteen months ended March 31, 2014.

Normal Course Issuer Bid

On February 3, 2014 the Company filed a normal course issuer bid ("NCIB") which authorized the Company to repurchase for cancellation up to 8,882,872 common shares until February 2, 2015 or the date by which the Company had acquired the maximum number of common shares under the NCIB. On February 3, 2015 the Company filed a renewal NCIB which authorizes 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.

During fiscal 2014 the Company repurchased a total of 983,000 common shares for $299,443 cash consideration. During fiscal 2015 the Company repurchased a total of 2,454,500 common shares for $371,803 cash consideration. From April 1, 2015 to the date of this MD&A the Company repurchased an additional 139,000 common shares of the Company for $21,025.

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 been 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).

Production from Cheal North East averaged of 296 net BOE's per day (72% oil) in Q4 2015 compared to an average of 279 BOE's per day (75% oil) in Q3 2015 and 573 BOE's per day in Q4 2014. The increase of 17 BOE's per day from Q3 2015 is due to the successful completion and tie-in of Cheal-E6 in December 2014 and the successful recompletion of Cheal-E2 in January 2015. The drop of 277 BOE's per day from Q4 2014 was the result of the East West receiving a preferential share of 100% the first $5 million in revenue.

The Cheal North East area development and step out drilling continues to achieve excellent results with current stabilized production of approximately 1,030 BOE/d gross (309 BOE/d net) from the Cheal-E Site pool. The successful Cheal-E1 well targeted a new pool down dip from the lowest known oil contact at TAG's Cheal field, and has been producing oil steadily since November 2013 at gross volumes of 500 to 600 BOEPD (82% oil) on choke, with no water. The Cheal E Site pool is being further developed and delineated with follow-up drilling, in both the Mount Messenger and Urenui formations.

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.

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.

East West has relinquished the following working interests in New Zealand:

PEP 54876 (Southern Cross) - East West 50%

In December 2012, East West was awarded a 50% interest in PEP 54876. As required under the initial work program two wells, the Southern Cross-1 and the Southern Cross-1ST1, were drilled and abandoned as non-commercial wells. In Q3 of 2015, East West relinquished its interest in PEP 54876 given the drilling results and lack of further prospective targets.

PEP 55770 - East West 40%

In December 2013, East West was awarded a 40% interest in PEP 55770 with partner TAG (60%). The block covers an area of 106,157 acres in the East Coast Basin unconventional fairway of New Zealand. Pursuant to a joint bid agreement, East West agreed to pay 100% of the costs up to a maximum of NZ $11.8 million of the initial work program which includes: reprocessing of existing seismic data in the first 12 months; acquisition of 60 km of 2D seismic data within the first 18 months and; the drilling of one exploration well in the first three years. A joint venture agreement was finalized and seismic reprocessing of the existing data and analysis of offsetting well data was conducted. After reviewing the results and data from the East Coast Basin the Company has decided not to proceed with the optional Phase 2 work program and it has subsequently relinquished its interest in the permit.

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.

Reconciliation of Company Gross (1) Reserves (Before Royalty)
by Principal Product Type
As of March 31, 2015

	Light and Medium Oil			Natural Gas			Barrels of Oil Equivlent		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
March 31, 2014	94.0	178.0	272.0	38.0	71.0	109.0	100.3	189.8	290.2
Infill Drilling	15.0	15.0	30.0	21.1	21.2	42.3	18.5	18.6	37.1
Technical Revisions	36.7	(56.5)	(19.8)	111.0	100.7	211.7	55.2	(39.7)	15.5
Economic Factors	(1.3)	(3.9)	(5.1)	(1.5)	(3.3)	(4.8)	(1.5)	(4.4)	(5.9)
Production	(71.2)	0.0	(71.2)	(79.9)	0.0	(79.9)	(84.5)	0.0	(84.5)
March 31, 2015	73.2	132.6	205.8	88.8	189.6	278.4	88.0	164.2	252.2

(1) The Gross Reserves presented here are the Company's working interest reserves before calculations of royalties, and before consideration of the Company's royalty interest.

Values may not add due to rounding

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

On June 30, 2010 the Company was awarded four exploration blocks, EX-2 (Tria), EX-3 (Baile Felix), EX-7 (Periam) and EX-8 (Biled), located in the Pannonian Basin in western Romania. Total acreage covered in the four blocks is approximately 1,000,000 acres. The Pannonian Basin is a prolific oil and gas basin with significant remaining potential for conventional oil and gas.

On May 20, 2011 the Company signed the four concession agreements with the National Agency of Mineral Resources ("NAMR"). The Company then entered into a binding memorandum of understanding agreement with Naftna Industrija Srbije j.s.c. Novi Sad ("NIS") to cooperate in the exploration and development of the four Romanian blocks. Under the terms of the agreement, NIS would acquire an 85% participation interest in all four blocks and pay 100% of the obligatory Phase I work program costs and optional Phase II work program costs.

On October 27, 2011 the Company entered into a farm-out agreement with NIS whereby NIS would acquire an 85% participation interest in the four Romanian blocks EX-2 (Tria), EX-3 (Baile Felix), EX-7 (Periam) and EX-8 (Biled) (collectively the "Concessions") and eventually assume operatorship. The Phase I program includes environmental baseline surveys, the acquisition and processing of a minimum of 900 km. of 2D and 600 sq. km. of 3D seismic data, with a minimum of 12 wells to be drilled on the four blocks. NIS will also pay 100% of the Company's sunk costs which totalled approximately $525,000. The Company retains a 15% carried interest in each block until the achievement of commercial production, at which time the Company will be responsible for its 15% interest in the commercial discoveries.

On December 23, 2011 the Company entered into four Joint Operating Agreements with NIS which provided for NIS to assume operatorship for the Concessions, subject to receiving NAMR's approval of change of operator.

In December 2012 the Romanian Government ratified the EX-2 Tria Concession. NAMR subsequently approved the farmout to NIS for an 85% participation interest in the Concession and approved change of operatorship to NIS. On

November 22, 2013, following publication in the Official Gazette of Romania No 0721, the EX-3 Baile Felix, EX-7 Periam and EX-8 Biled Concessions were formally ratified.

Initial work during the ratification processed focussed on environmental studies and the review and interpretation of existing historic data on the licenses to identify prospective areas for future focus. Following ratification, NIS, as operator, has commenced the acquisition of 2D and 3D seismic data. Once acquisition and analysis is completed, the newly acquired seismic data will be used to select the drilling locations of the 12-well exploration program across the licenses.

United States

On September 4, 2012 the Company announced it had signed 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. In conjunction with the joint exploration program, the Company also made an investment of US $500,000 as part of Lani's planned restructuring as a public US company named North American Oil and Gas ("NAMG"). NAMG began trading as a public company in November 2012, with the Company owning an initial 8.3% interest.

On November 19, 2012 the Company announced it had completed a farm-in agreement, which superseded the September 4, 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. Under the agreement the Company agreed to fund US $2,200,000 to be used in the drilling of two exploratory wells and to acquire additional joint leases in the area and provide a US $300,000 loan for G&A funding.

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 has determined that this well is unlikely to be commercial and the costs associated with the 77-20 well were provided for.

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 on the properties, the Company has made a full impairment charge on the properties.

Morocco

On September 30, 2011 the Company and the Office National des Hydrocarbures et des Mines ("ONHYM"), an agency of the Moroccan government, entered into agreements whereby the Company was granted a 75% participation interest in the Doukkala exploration permit (the "Exploration Permit") covering approximately 500,000 acres situated along the Atlantic coast approximately 125 kilometres southwest from Casablanca, Morocco. The Exploration Permit had an overall duration of eight years, comprising three Phases. During the three-year Phase 1 period, the Company was required to carry out geological and geophysical studies to assess the conventional and unconventional potential of the acreage. The cost of the Phase I work program was estimated at US $5,500,000. The Company provided a US $3,500,000 guarantee in favour of ONHYM as security for performance of the Phase 1 program. On August 15, 2014 a demand (the "Demand") was made by ONHYM for payment of the guarantee amount and the Guarantee was subsequently released. The joint venture with ONHYM is, effectively, terminated.

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.

Investments

North American Oil and Gas Corp. ("NAMG")

During fiscal 2012 the Company purchased 5,000,000 common shares of NAMG (the NAMG Shares") for US $500,000. The NAMG Shares were sold in fiscal 2015 for net proceeds of $200,253 and the Company recognized a realized loss of $298,247.

North South Petroleum Corp. ("North South")

On April 9, 2015 the Company acquired ownership and control over 3,900,000 common shares (the "North South Shares") in the capital of North South pursuant to a non-brokered private placement conducted by North South through the facilities of the NEX board of the TSX Venture Exchange. The consideration paid for each share was $0.05, for an aggregate consideration of $195,000.

As a result of the acquisition of the North South Shares, the Company owns and controls a total of 3,900,000 common shares in the capital of North South, representing approximately 16.74% of the issued and outstanding common shares of North South. The Company acquired the North South Shares for investment purposes and may in the future acquire or dispose of securities of North South, through the market, privately or otherwise, as circumstances or market conditions warrant.

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. The Company's judgment is that it has significant influence over North South and, accordingly, will account for the investment under the equity method.

As of the date of this MD&A the Company has purchased an additional 80,000 common shares of North South through the public market for a total consideration of $20,430.

Selected Financial Data

The following selected consolidated financial information is derived from the audited consolidated financial statements prepared in accordance with IFRS. Due to the change in the Company's year end, the following information includes the 12 month period ended March 31, 2015, the 15 month period ended March 31, 2014 and the 12 month period ended December 31, 2012.

	Twelve Months Ended March 31, 2015 $	Fifteen Months Ended March 31, 2014 $	Twelve Months Ended December 31, 2012 $
Operations:			
Revenues, net of costs	4,182,413	3,221,392	58,269
Expenses	(11,100,494)	(8,352,631)	(3,055,876)
Other items	358,646	(2,302,140)	311,861
Loss before deferred income tax	(6,559,435)	(7,433,379)	(2,685,746)
Deferred income tax	(25,000)	(425,000)	450,000
Net loss	(6,584,435)	(7,858,379)	(2,235,746)
Other comprehensive (loss) income, net	(712,620)	(2,147,177)	3,180,335
Comprehensive (loss) income	(7,297,055)	(10,005,556)	944,589
Basic and diluted loss per share	(0.07)	(0.09)	(0.03)
Dividends per share	Nil	Nil	Nil
Balance Sheet:			
Working capital	8,901,697	10,966,215	21,254,627
Total assets	19,539,844	29,682,150	31,455,981
Total long-term liabilities	(1,062,292)	(995,388)	(81,404)

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

	Fiscal 2015				Fiscal 2014				
	Mar. 31 2015 $	Dec. 31 2014 $	Sep. 30 2014 $	Jun. 30 2014 $	Mar. 31 2014 $	Dec. 31 2013 $	Sep. 30 2013 $	Jun. 30 2013 $	Mar. 31 2013 $
Operations:									
Revenues, net of costs	747,049	899,935	1,371,347	1,164,082	3,136,475	18,591	17,716	26,060	22,550
Expenses	(3,681,902)	(2,441,979)	(1,272,702)	(3,703,911)	(5,707,656)	(410,353)	(577,652)	(1,068,265)	(588,705)
Other items	1,140,999	(132,379)	204,035	(854,009)	(3,025,455)	368,729	(96,721)	256,317	194,990
(Loss) income before deferred income tax	(1,793,854)	(1,674,423)	302,680	(3,393,838)	(5,596,636)	(23,033)	(656,657)	(785,888)	(371,165)
Deferred income tax	Nil	Nil	Nil	(25,000)	(210,000)	(340,500)	17,500	154,000	(46,000)
Net income (loss)	(1,793,854)	(1,674,423)	302,680	(3,418,838)	(5,806,636)	(363,533)	(639,157)	(631,888)	(417,165)
Other comprehensive income (loss), net	(360,051)	667,968	(1,187,515)	166,978	(626,442)	(2,768,875)	123,855	1,449,400	(325,115)
Comprehensive (loss) income	(2,153,905)	(1,006,455)	(884,835)	(3,251,860)	(6,433,078)	(3,132,408)	(515,302)	817,512	(742,280)
Basic and diluted (loss) income per share	(0.02)	(0.01)	0.01	(0.03)	(0.07)	(0.00)	(0.01)	(0.01)	(0.01)
Dividends per share	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Balance Sheet:									
Working capital	8,901,697	8,591,136	9,362,466	8,745,415	10,966,215	15,487,110	18,964,676	19,437,767	20,715,806
Total assets	19,539,844	21,794,694	22,510,465	23,426,418	29,682,150	34,952,549	35,939,795	31,681,207	30,735,830
Decommissioning liabilities	(1,062,292)	(952,108)	(886,520)	(983,377)	(995,388)	(516,664)	(248,841)	(81,741)	(78,438)

Results of Operations

Three Months Ended March 31, 2015, Three Months Ended December 31, 2014, and Three Months Ended March 31, 2014.

Revenues and operating costs for the three months ended March 31, 2015 compared to the three months ended December 31, 2014 and the three months ended March 31, 2014 are as follows:

	Three Months Ended		
	March 31 2015 (Q4/15)	**December 31 2014 (Q3/15)**	**March 31 2014 (Q5/14)**
Sales	17,782 BOE	19,345 BOE	31,112 BOE
Petroleum and natural gas sales	$ 1,264,464	$ 1,463,054	$ 4,067,344
Average realized price	$ 71.11	$ 75.63	$ 130.73
Production costs	$ 252,592	$ 257,855	$ 367,056
Average per BOE	$ 14.20	$ 13.33	$ 11.80
Transportation and storage costs	$ 213,836	$ 241,211	$ 391,009
Average per BOE	$ 12.03	$ 12.47	$ 12.57
Royalties	$ 50,987	$ 64,053	$ 172,804
Average per BOE	$ 2.87	$ 3.31	$ 5.55
Netback	$ 747,049	$ 899,935	$ 3,136,475
Average per BOE	$ 42.01	$ 46.52	$ 100.81

Sales volumes decreased to 17,782 BOE in Q4/15 compared to 19,345 BOE in Q3/15 and 31,112 BOE in Q5/14. The drop of 1,563 BOE in production from Q3/15 to Q4/15 was primarily a result of the lifting schedule during the period which determines the number of and size of sailings of crude oil. The decline of 13,330 BOE from Q5/14 compared to Q4/15 is due to the Company having received 100% of the first $5 million in revenue from the sale of oil in Q5/14 as a result of the joint operating agreement with TAG. Under the joint operating agreement, the Company funded the cost of the first two wells on PEP 54877 up to $5 million in return for receiving 100% of the first $5 million in revenue before reverting back to its working interest share of 30%. On February 4, 2014 the Company had recovered its initial $5,000,000, after which all subsequent net revenues are being shared according to each party's interest.

Petroleum and natural gas sales decreased from $1,463,054 in Q3/15 to $1,264,464 in Q4/15, a decline of 14%. Decreased sales volumes accounted for approximately 8% of the drop, while lower realized prices contributed a further 6%.

There was a decrease in production costs in Q4/15 to $252,592 from $257,855 in Q3/15 and $367,056 in Q5/14 driven by reduced sales volumes of crude oil. On a per barrel basis, there was a slight increase in production costs as a result of the fixed costs associated with production being spread over a smaller sales volume.

Transportation and storage costs decreased slightly to $213,836 in Q4/15 from $241,211 in Q3/15 and $391,009 in Q5/14 due to reduced sales volumes. In Q5/14, while the Company was recovering the first $5 million in revenue, it was paying 100% of the costs to produce that revenue, resulting in higher transportation and storage costs in Q5/14.

As a result of lower sales volumes and reduced commodity prices, royalties declined to $50,987 in Q4/15 from $64,053 in Q3/15 and $172,804 in Q5/14. The much higher royalties in Q5/14 were due to the Company paying 100% of the royalties associated with the first $5 million in revenue from Cheal-E.

Twelve Months Ended March 31, 2015 Compared to Fifteen Months Ended March 31, 2014

The Company's primary source of petroleum revenues were derived from the Cheal-E1 well which did not achieve commercial production until January 7, 2014, at which time the Company commenced recognizing the revenues and associated costs from the Cheal-E1 in profit and loss. Additionally, the Company received 100% of the revenues until it recovered its initial $5,000,000 funding on PEP 54877, after which it then received its 30% working interest.

Revenues and costs for the twelve months ended March 31, 2015 (“fiscal 2015”) compared to the fifteen months ended March 31, 2014 (“fiscal 2014”) are as follows:

	Fiscal 2015	**Fiscal 2014**
Sales	73,692 BOE	36,434 BOE
Petroleum and natural gas sales	$ 6,547,177	$ 4,241,836
Average realized price	$ 88.85	$ 116.43
Production costs	$ 1,168,612	$ 448,577
Average per BOE	$ 15.86	$ 12.31
Transportation and storage costs	$ 908,333	$ 391,009
Average per BOE	$ 12.33	$ 10.73
Royalties	$ 287,819	$ 180,858
Average per BOE	$ 3.91	$ 4.96
Netback	$ 4,182,413	$ 3,221,392
Average per BOE	$ 56.76	$ 99.15

Sales volumes of crude oil increased by 37,258 BOE from 36,434 BOE in fiscal 2014 to 73,692 BOE in fiscal 2015. In fiscal 2014 the Company did not commence recognizing petroleum revenues from the Cheal-E1 well until declaration of commercial production on January 7, 2014. The Company recognized 100% of the revenues until February 4, 2014 after which it received its working interest of 30%. Revenues for fiscal 2015 reflect a full year’s production from the Cheal-E1 well.

Despite an approximately 24% decrease in realized sales prices per BOE, revenue from oil sales increased to $6,547,177 in fiscal 2015 from $4,241,836 in fiscal 2014 as a result of increased sales volumes.

Per BOE production and storage costs increased from $12.31 in fiscal 2014 to $15.86 in fiscal 2015. Transportation and storage costs increased to $12.33 per BOE in fiscal 2015 from $10.73 per BOE in fiscal 2014. These increases were primarily due to increased sales volumes extending throughout fiscal 2015 and the increase in fixed facility costs as production was expanded at the Cheal E site.

Royalties decreased from $4.96 per BOE in fiscal 2014 to $3.91 in fiscal 2015 per BOE due to lower realized sales prices of crude oil over fiscal 2015.

During fiscal 2015 the Company reported a net loss of $6,584,435 ($0.07 per share) compared to a net loss of $7,858,379 ($0.09 per share) during fiscal 2014, a decrease in loss of $1,273,944. The overall decrease in loss during fiscal 2015 was attributed primarily to the following:

(i) the increase in revenue and costs of $961,021 in fiscal 2015 compared to fiscal 2014;
(ii) the overall increase in expenses of $2,747,863 from $11,100,494 in fiscal 2015 to $8,352,631 in fiscal 2014 mainly due to the recognition of general exploration expenses in fiscal 2015 mainly for costs incurred on PEP 54876; and
(iii) recognition of the provision of the $3,868,550 guarantee amount in fiscal 2014, and which was forfeited to ONHYM on August 15, 2014. See also “Projects Update - Morocco”.

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

	2015 $	**2014 $**
Accounting and administrative	62,535	70,195
Audit and related	83,021	38,250
Bank charges and letter of credit fees	58,477	40,398
Corporate development	29,582	15,945
Legal	55,508	104,075
Office	36,132	71,021
Other (recovery)	(16,533)	-
Professional fees	841,498	1,060,108

	2015 $	2014 $
Regulatory fees	15,929	21,290
Rent	68,502	42,452
Salaries and benefits	66,662	395,065
Shareholder costs	4,179	8,386
Telephone	11,272	12,532
Transfer agent fees	6,713	12,815
Travel	214,957	330,000
	1,538,434	2,222,532

General and administrative expenses of $1,538,434 were reported for fiscal 2015 compared to $2,222,532 during fiscal 2014. Specific expenses of note for fiscal 2015 and fiscal 2014 period are as follows:

(i) professional fees totalling $841,498 (2014 - $1,060,108) were paid of which $659,500 (2014 - $707,866) were paid to current and former directors and officers of the Company (see "Related Party Transactions"), $105,868 (2014 - $155,993) were paid to consultants for administrative consulting and $76,130 (2014 - $196,249) were paid to consultants for financial consulting. Professional fees paid to consultants for administrative consulting in fiscal 2015 decreased by $50,125, from $155,993 in fiscal 2014 to $105,868, in fiscal 2015, reflecting the hiring of a consultant as an employee of the Company effective October 1, 2014. Professional fees paid to consultants for financial consulting decreased by $120,119, from $196,249 in fiscal 2014 to $76,130 in fiscal 2015, reflecting the reduced levels of financial services required in fiscal 2015;

(ii) legal fees of $55,508 (2014 - $104,075) were paid. During fiscal 2014 period the Company incurred significant legal fees due to the number of corporate transactions conducted with its joint venture partner, TAG;

(iii) salaries and health benefits decreased by $328,403, from $395,065 in fiscal 2014 to $66,662 in fiscal 2015. In fiscal 2014 the amounts were incurred for Mr. Greg Renwick, the former President and CEO, and Mr. Barry Chovanetz, the former Vice-President of Operations. In fiscal 2015, Mr. David Sidoo's compensation as the Company's President and CEO was billed to the Company and recorded as professional fees. In addition, commencing October 1, 2014 the Company hired a former consultant as an employee. During fiscal 2015 the Company paid the employee $66,662;

(iv) rent expense of $68,502 (2014 - $42,452) was incurred by the Company. The Company previously had an agreement with a public company, which was related through a common director and officer, to share office premises. During fiscal 2014 period the Company received a recovery of $25,425. On March 31, 2014 the arrangement was terminated and, accordingly, the Company did not receive any recoveries during fiscal 2015. See also "Related Party Disclosures";

(v) audit and related fees of $83,021 (2014 - $38,250) were paid reflecting an increase in the scope of audit procedures;

(vi) bank charges of $58,477 (2014 - $38,250) were incurred by the Company. During fiscal 2015 the Company incurred additional bank fees on the release of the guarantee in favor of ONHYM.

(vii) office expenses decreased by $34,889 from $71,021 in fiscal 2014 to $36,132 in fiscal 2015 due to the closure of the US office in fiscal 2014; and

(viii) travel expenses decreased by $115,043 from $330,000 in fiscal 2014 to $214,957 in fiscal 2015 due to reduction of travel.

During fiscal 2015 the Company recorded general exploration expenses of $2,990,586 (2014 - $213,917) of which $2,732,060 was incurred for the drilling and abandonment of PEP 54876 and $258,526 (2014 - $213,917) was for ongoing review of current and potential exploration and evaluation assets.

During fiscal 2015 the Company recorded share-based compensation expense of $588,050 (2014 - $435,288) on the granting and vesting of share options. In addition the Company recorded share-based compensation expense of $67,582 (2014 - $84,000) on the re-pricing of certain share options.

During fiscal 2015 the Company sold 5,000,000 shares of NAMG for proceeds of $200,253 recognizing a realized loss of $298,247. The Company also recorded a comprehensive loss of $194,945 (2014 - 2,985,390), net of deferred income tax recovery of $25,000 (2014 - 425,000).

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 fiscal 2015 the Company reported interest income of $114,456, a decrease of $197,687, compared to $312,143 for fiscal 2014. The decrease in interest income in fiscal 2015 was due to lower levels of cash compared to fiscal 2014 and lower yields obtained during fiscal 2015.

During fiscal 2015 the Company repurchased 2,454,500 (2014 - 983,000) common shares for $371,803 (2014 - $299,443). See also "Normal Course Issuer Bid".

Exploration and Evaluation Assets

	New Zealand				United States			
	PEP 54876 $	PEP 54877 $	PEP 54879 $	PEP 55770 $	Tejon Ranch Extension $	Tejon Main Area $	White Wolf $	Total $
Balance at December 31, 2012	-	-	-	-	817,017	-	52,327	869,344
Capital expenditures	2,195,195	8,087,972	5,223,273	-	613,569	122,154	265,794	16,507,957
Net revenues pre-commercial discovery	-	(1,548,553)	-	-	-	-	-	(1,548,553)
Provision for decommissioning liabilities	223,243	282,518	223,243	-	32,525	-	-	761,529
Transfer to property, plant and equipment	-	(6,821,937)	-	-	-	-	-	(6,821,937)
Foreign exchange movement	80,662	-	219,899	-	-	-	-	300,561
Impairment	(2,499,100)	-	-	-	(1,463,111)	-	-	(3,962,211)
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

During fiscal 2015 the Company incurred a total of $353,101 (2014 - $16,507,957) for exploration and evaluation assets comprising of $353,101 (2014 - $15,506,440) on the New Zealand properties and $nil (2014 - $1,001,517) on the US properties. During fiscal 2015 the Company received net revenues of $44,972 from production from the testing of the G1 well on PEP 54879. In addition during fiscal 2015 the Company recorded an impairment of $503,632 (2014 - $3,962,211) on its exploration and evaluation assets comprising of $63,357 (2014 - $2,499,100) on the New Zealand properties and $440,275 (2014 - $1,463,111) on the US properties.

Details of the Company's activities are discussed in "Projects Update".

Property, Plant and Equipment

During fiscal 2015 the Company incurred total additions of $1,760,940 (2014 - $912,390), net of a $60,983 (2014 - $119,163) increase for the revision in estimate for decommissioning costs and a decrease $30,122 (2014 - increase $842,917) in foreign exchange movement for property, plant and equipment additions.

At March 31, 2015 the Company assessed the recoverability of its investment in petroleum and natural gas properties by performing impairment tests at the cash-generating unit levels. The recoverable amounts of each cash-generating unit were estimated based on the higher of the value in use and the fair value less costs to sell. The estimated fair value less costs to sell was used and was determined using estimated future cash flows based on estimated reserves, discounted at 10%. Based on the impairment tests, the carrying amounts of the investments in PEP 54877 and the Carbon Property were determined to be impaired in the amounts of $2,507,939 and $60,500 respectively, for a total impairment expense of $2,568,439 in fiscal 2015. No impairment charge was required in fiscal 2014.

Financial Condition / Capital Resources

As at March 31, 2015 the Company had cash resources of $8,401,122 a decrease of $3,872,688 from $12,273,810 as at March 31, 2014. The decrease in cash resources is mainly from the Company's use of resources for its expenditures on the New Zealand properties, ongoing operations and administration.

As at March 31, 2015 the Company had working capital of $8,901,697. 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	92,460	69,420	23,040
Other long-term obligations	2,715,280	1,747,140	968,140
Total contractual obligations	2,807,740	1,816,560	991,180

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 fiscal 2015 and 2014 the following amounts were incurred with respect to the Company's current President and Chairman (Mr. David Sidoo), the former President (Mr. Greg Renwick), the Chief Financial Officer ("CFO") and Corporate Secretary (Mr. Nick DeMare), and the former Vice-President of Operations (Mr. Barry Chovanetz):

	2015 $	2014 $
Salaries - Greg Renwick	-	191,940
Salaries - Barry Chovanetz	-	180,303
Health benefits - Greg Renwick	-	3,406
Health benefits - Barry Chovanetz	-	10,250
Professional fees - David Sidoo (1)	196,500	115,500
Professional fees - Nick DeMare (2)	52,000	48,000
Share-based compensation - Greg Renwick	-	18,666
Share-based compensation - Barry Chovanetz	-	25,202
Share-based compensation - David Sidoo	183,153	198,130
Share-based compensation - Nick DeMare	125,230	34,769
	556,883	826,166

(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 March 31, 2015, $nil (2014 - $3,500) remained unpaid.

(b) *Transactions with Other Related Parties*

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

	2015 $	2014 $
Professional fees - Marc Bustin, Director (1)	341,000	465,000
Professional fees - Herb Dhaliwal, Director (2)	70,000	55,000
Professional fees - James Dewar, former Director	-	6,000
Legal - James Harris, former Corporate Secretary	-	51,061
Share-based compensation - Marc Bustin, Director	126,480	66,684
Share-based compensation - Herb Dhaliwal, Director	126,357	28,975
Share-based compensation - James Dewar, former Director	-	11,666
	663,837	684,386

(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 March 31, 2015, $23,000 (2014 - $31,000) remained unpaid.

(ii) During fiscal 2015 the Company incurred a total of $60,550 (2014 - $52,850) to Chase for accounting and administration services provided by Chase personnel, excluding Mr. DeMare. As at March 31, 2015, $9,000 (2014 - $6,500) remained unpaid.

(iii) During fiscal 2014 the Company paid $3,153 to Ms. Galena Renwick, the spouse of Mr. Renwick, for professional services rendered.

(c) The Company previously had an agreement with Ava Resources Corp. ("Ava"), to share office premises. On March 31, 2014 Ava was dissolved. During fiscal 2015 the Company recorded the $16,533 rent deposit which was forfeited by Ava as a credit to general and administrative expenses. Ava was a public company of which Messrs. Sidoo, DeMare and Dhaliwal were also directors and/or officers.

(d) On March 6, 2015 the Company entered into a letter of intent (the "LOI") with Frontier Natural Resources Inc. ("Frontier") whereby it agreed to provide Frontier a credit facility of US $250,000 (the "Credit Facility"). The LOI contemplates the negotiation of a definitive credit agreement and the exploration of a potential acquisition of 100% of the capital of Frontier. As at March 31, 2015 the Company had advanced US $165,000 and the remaining US $85,000 was advanced in April 2015. Frontier is a privately held oil and natural gas company incorporated in Pennsylvania, U.S.A. in 2014. Mr. Bustin, a director of the Company, is also a shareholder and director of Frontier.

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 March 31, 2015 or 2014 and did not provide for any doubtful accounts. The Company has recorded a provision of $119,488 on its deposits.

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.

The Company did not have any commodity price contracts in place as at or during the fiscal 2015 and 2014.

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 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 fiscal 2015 and 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 four categories: fair value through profit or loss ("FVTPL"); held-to-maturity investments; loans and receivables; and available-for-sale.

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, accounts payable and accrued liabilities and amounts due to joint venture partner 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.

Investor Relations Activities

The Company provides information packages to investors; the package consists of materials filed with regulatory authorities. The Company updates its website (www.eastwestpetroleum.ca) on a continuous basis.

Outstanding Share Data

The Company's authorized share capital is unlimited common shares with no par value. As at July 28, 2015, there were 90,515,165 outstanding common shares (net of shares repurchased) and 7,242,000 share options outstanding with exercise prices ranging from $0.14 to $0.50 per share.