EAST WEST PETROLEUM CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED MARCH 31, 2022

This discussion and analysis of financial position and results of operation is prepared as at July 29, 2022 and should be read in conjunction with the audited consolidated financial statements for the years ended March 31, 2022 and 2021 of East West Petroleum Corp. ("East West" or the "Company"). The following disclosure and associated consolidated 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.

COVID - 19

In March 2020 the World Health Organization ("WHO") declared the novel coronavirus outbreak identified as "COVID-19", as a global pandemic. In order to combat the spread of COVID-19 governments worldwide enacted emergency measures including travel bans, legally enforced or self-imposed quarantine periods, social distancing and business and organization closures. These measures caused material disruptions to businesses, governments and other organizations resulting in an economic slowdown and increased volatility in national and global equity and commodity markets. The Company implemented safety and physical distancing procedures, including working from home where possible and curtailed travel. The Company will continue to monitor the impact of the COVID-19 outbreak, the duration and impact which is unknown at this time, as is the efficacy of any intervention. It is not possible to reliably estimate the length and severity of these developments and the impact on the financial results and condition of the Company and its operations in future periods.

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 currently 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. The Company's principal office is located at #1305 - 1090 West Georgia Street, Vancouver, BC, V6E 3V7.

The Company had previously agreed to sell its interest in PEP 54877 and PMP 60291 which comprise the majority of its New Zealand assets. The agreement was terminated by the Company on August 1, 2020. The Company is currently assessing its go-forward plans, which includes the possible sale of its New Zealand concessions to other buyers and ongoing discussions on the Teremia North Field in Romania, and whether its focus should remain on the oil and gas sector. At this time no decisions have been made but the Company continues to assess alternatives.

Directors and Officers

As of the date of this MD&A the Company's Board of Directors and Officers are as follows:

Nick DeMare	- Interim CEO, Chief Financial Officer ("CFO"), Corporate Secretary and Director
Mark Brown	- Director
Kevin Haney	- Director

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 operations in the Taranaki Basin of New Zealand. All licenses were previously operated by the Company's original partner, TAG Oil Ltd. ("TAG"), and all wells are targeted 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 the Cheal field. The Company holds a 30% working interest in the Petroleum Exploration Permit ("PEP") 54877 and the Petroleum Mining Permit PMP 60291 ("Cheal East") and TAG held the remaining 70%. On September 25, 2019 TAG completed the sale of substantially all of its Taranaki Basin assets and operations which included their interest in PEP 54877 and PMP 60291 to Tamarind Resources Pte. Ltd. ("Tamarind") resulting in Tamarind becoming the operator. In light of TAG's decision to sell the majority of its interest in the Taranaki Basin assets the Company assessed its options with respect to its 30% interest in Cheal East and, on June 24, 2019, the Company signed a heads of agreement pursuant to which the Company had agreed to sell its 30% interest in PEP 54877 and PMP 60291. On August 1, 2020 the Company terminated the Definitive Agreement.

When TAG's interests in the Taranaki Basin were sold to Tamarind in September 2019 and as part of the transaction Tamarind acquired Cheal Petroleum Ltd. ("Cheal"), the owner of 70% of PEP 54877 and PMP 60291, and operator. There have been ongoing discussions regarding the operator, including whether there has been a subsequent change of control, triggering rights of first refusal, and the ability for Cheal to continue as operator. The Company is seeking clarification on this issue and legal action may be required.

During fiscal 2022 Cheal conducted a detailed prospectivity review of PEP 54877 and advised the Company that the forecasted economic prospects of PEP 54877 does not meet Cheal's internal risk criteria. Although no final decision has been made to relinquish the permit in December 2022, the Company has determined to record an impairment of $1,627,056 for costs incurred to March 31, 2022.

PMP 60291 is the location of the Cheal E-Site and the Cheal E-site production facility as well as the Cheal-E wells. A waterflood program is ongoing however the efficacy of the program and its impact on production is an ongoing item of debate. The Company's technical advisors have stated that there is no unequivocal evidence that water injection through the Cheal-E7 well has had a significant impact on production from PNP 60291 but that there is evidence to the contrary. The Company's advisors attribute the production performance to other factors than injection through the Cheal-E7 well. The determination whether the waterflood utilizing Cheal-E7 as the injector well is creating the positive response in production impacts the Company's obligation to fund its 30% share of the costs of acquiring the Cheal-E7 well, being 30% of NZ $3,200,000. No funding has been advanced, and no funding will be advanced until the issue is resolved.

The Company produces its oil and gas production from five wells on the Cheal-E site. On October 24, 2020 the Cheal-E1 pump stopped functioning due to downhole blockage and, as a result, production ceased from the Cheal-E1 well. As the major producing well, the stoppage of the Cheal-E1 well had a major impact on the Company's share of production. In mid-January the Operator managed to pull the rods out of the Cheal-E1 well with a crane, cleaned the well and replaced the pump. However, only limited production resumed in mid-January 2021 without annular flow. In addition, in early March 2021 the Cheal-E2 well stopped working and several attempts to restart the well over the following three weeks were unsuccessful. Workovers of the Cheal-E1 well and the Cheal-E2 well were not completed until early August 2021 including the clearing of downhole wax and sand issues. The workovers were successful in re-establishing production in both wells. A trial of a two-stage downhole pump in Cheal-E1 proved to be too vulnerable to sand production issues and was replaced with a single stage downhole pump as previously employed. This is working reliably and an increase in flow was successfully implemented in Q3/2022.

As a result of the continued Cheal-E1 stoppage and the addition of the stoppage of the Cheal-E2 well, oil and gas production was significantly less from October 2020 to early August 2021. Only three wells, the Cheal-E5, E6 and E8 were fully producing for Q1/2022. During Q2/2022 all five wells the Cheal-E1, E2, E5, E6 and E8 were producing.

During Q4/2022 the Company produced 18.3 Mbbl oil and 11.6 Mmcf gas. compared to 19.5 Mbbl oil and 15.1 Mmcf gas during Q3/2022. The decreases were a result of both the Cheal E-5 and Cheal E-6 wells going offline for the last month of Q3. The Cheal E-5 went down due to a downhole related issue which appears to be parted rods. Workover planning is currently underway with a full workover being scheduled for the end of Q2/2023. The Cheal E-6 went offline due to downhole related issues which appears to be a wax plug. The operator carried out rod work and installed a new pump while the well was off line. The Cheal E-6 started back on-line near the end of March 2022.

In March 2021 the Company retained a technical advisory team in New Zealand to assist in oversight over operations at the Cheal site. The Company retained 3TCF Limited ("3TCF"), a private New Zealand corporation, to provide oversight and guidance on operating matters. Since the start of the Covid-19 pandemic travel has been difficult for both the Company and the permit operator. As a result, the Company now has a New Zealand based technical team which can provide oversight over ongoing operations.

Reserves Data

An independent reserves evaluation relating to the resource base of the Company in the Cheal Area of New Zealand, effective March 31, 2022, 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
by Principal Product Type as of March 31, 2022

	Light and Medium Crude Oil			Solution Gas			Barrels of Oil Equivalent		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
March 31, 2021	60	18	78	37	11	48	66	20	86
Technical Revisions (2)	(30)	(16)	(47)	(14)	(10)	(24)	(33)	(18)	(51)
Economic Factors	15	4	19	9	2	11	17	4	21
Production	(20)	0	(20)	(17)	0	(17)	(22)	0	(22)
March 31, 2022	25	6	31	15	3	18	28	6	34

(1) The Gross Reserves presented here are the Company's working interest reserves before deductions of royalties.
(2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.
(3) Totals in the above table may not add due to rounding.

Gross proved plus probable ("2P") reserves estimates within the Taranaki Basin at March 31, 2022 were 34 MBOE compared to the March 31, 2021 2P reserves of 86 MBOE. Taking into account the 22 MBOE the Company produced over the fiscal year and the 51 MBOE decrease for technical revisions plus the 21 MBOE increase for economic factors, the Company's reserves overall decreased by 39.5%.

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 $63,000,000 for all four programs. Production from the concessions is also subject to royalties of between 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 has paid the Company a total of $525,000 for the assignment of an 85% participation interest and operatorship of the Romania Work Programs to NIS. NIS is the operator of the four concessions and 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 Phase I work program and an optional one-year Phase II work program which carries additional commitments. If a commercial discovery is made, the Company will be responsible for its 15% interest in development of the commercial discovery.

As operator, NIS has reported resumption of exploration and production activities in the EX-2, EX-3, EX-7 and EX-8 exploration blocks in Romania. EWP has a 15% carried interest during the commitment work programs in all four blocks which includes for the drilling of a total of twelve exploration wells (three per block). It should be noted that all activities are dependent on securing the necessary government and local approvals.

Blocks EX-2 and EX-3

Interpretation of seismic data has continued although no commercially viable exploration prospects have been identified to date. NIS has proposed to request an extension of the exploration periods beyond the contractual maximum of ten years while the prospectivity of the blocks is under review. No commitment wells have been drilled to date in either block.

Block EX-7

Two phases of testing have been performed on exploration well BVS-1000. Despite fracture stimulation in the second testing phase, oil production from the well has rapidly declined to currently around 30 bopd. NIS consider the well has invalidated the pre-drill subsurface geological model and re-interpretation of the prospect is underway prior to a decision to either suspend or abandon the well. Deviated appraisal well, Teremia-1001, drilled on the Teremia North Field, has been completed as a production well after a period of experimental production testing.

All work program commitments in the block have been met.

Block EX-8

Testing of exploration well Pesac-1000 has been completed although with negative results. Deviated appraisal well Teremia-1002, drilled on the Teremia North Field, has been completed as a production well after a period of experimental production testing. Exploration well, Teremia-1201, was drilled to test a possible extension to the Teremia North Field but failed to encounter hydrocarbons. It was subsequently sidetracked into the Teremia North Field in 4Q/2021 and has now been completed as a production well and renamed Teremia-1004.

There have been several meetings of both the technical and operating committees to discuss work program results and determine whether the Teremia North field is a commercial discovery. At the operating committee meeting held

February 8, 2021 NIS voted that there was a commercial discovery at Teremia North whereas the Company voted that there was not a commercial discovery. The field economics were, in the Company's assessment, marginal and did not merit the significant capital contributions required. NIS, being a vertically integrated oil and gas producer, could support the development costs given the internal economies available.

Without a joint declaration of a commercial discovery it is the Company's position that commercial development of the field cannot proceed, NIS did not share this opinion. Rather than litigating this issue the discussions continued with NIS in an attempt to find a way forward. Given the consequences of a commercial discovery decision and significant funding obligations the Company and NIS continued negotiations on all available options including a monetization event. Negotiations were progressing well and the parties were moving towards final documentation with essential terms of a monetization event agreed, being some limited cash and a royalty interest.

The outbreak of war between Ukraine and Russian brought all attempts to implement the agreed terms to a halt, with the issue being that NIS is owned, in part, by a Russian entity which is subject to sanctions. The Company is considering what steps could be implemented to allow the transaction to proceed.

Selected Financial Data

The following selected financial information is derived from the audited annual consolidated financial statements prepared in accordance with IFRS.

	Year Ended March 31,		
	2022 $	2021 $	2020 $
Operations:			
Total revenues	1,753,974	2,443,384	3,676,561
Operating costs	(1,676,875)	(2,320,192)	(1,881,842)
Expenses	(2,083,448)	(672,508)	(966,870)
Other items	(34,241)	(35,256)	62,941
Net income (loss)	(2,040,590)	(584,572)	890,790
Other comprehensive income (loss)	304,802	54,591	(353,831)
Comprehensive income (loss)	(1,735,738)	(529,981)	536,959
Basic and diluted income (loss) per share	(0.02)	(0.01)	0.01
Balance Sheet:			
Working capital	5,138,429	5,150,053	4,977,101
Total assets	5,729,891	7,543,821	8,287,295
Decommissioning liabilities	(1,185,985)	(1,219,000)	(1,269,824)

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

	Fiscal 2022				Fiscal 2021			
	Mar. 31 2022 $	Dec. 31 2021 $	Sep. 30 2021 $	Jun. 30 2021 $	Mar. 31 2021 $	Dec. 31 2020 $	Sep. 30 2020 $	Jun. 30 2020 $
Operations:								
Total revenues	396,309	644,832	422,791	290,042	838,863	469,380	594,108	541,033
Operating costs	(194,014)	(461,799)	(394,712)	(626,350)	(607,654)	(595,781)	(476,631)	(640,126)
Expenses	(1,691,981)	(134,620)	(149,058)	(107,789)	10,522	(124,104)	(297,238)	(261,688)
Other items	(66,924)	(16,150)	42,198	6,635	(487,074)	245,896	140,004	65,918
Net income (loss)	(1,556,610)	32,263	(78,781)	(437,462)	(245,343)	(4,609)	(39,757)	(294,863)
Other comprehensive (loss) income	441,024	(55,827)	60,310	(140,705)	(46,134)	94,177	(148,613)	155,161
Comprehensive income (loss)	(1,115,586)	(23,564)	(18,471)	(578,167)	(291,477)	89,568	(188,370)	(139,702)
Basic and diluted income (loss) per share	(0.02)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)
Balance Sheet:								
Working capital	5,138,429	4,661,494	4,611,332	4,589,951	5,150,053	5,515,625	4,828,924	4,905,885
Total assets	5,729,891	6,880,928	6,887,457	7,070,388	7,543,821	8,068,039	7,735,963	8,130,220
Decommissioning liabilities	(1,185,985)	(1,200,848)	(1,216,612)	(1,201,670)	(1,219,000)	(1,368,938)	(1,325,303)	(1,329,460)
Deposit	Nil	Nil	Nil	Nil	Nil	Nil	Nil	(70,935)

Results of Operations

Three Months Ended March 31, 2022 ("Q4/2022"), Three Months Ended December 31, 2021 ("Q3/2022"), and Three Months Ended March 31, 2021 ("Q4/2021").

Revenues and operating costs for Q4/2022, Q3/2022 and Q4/2021 are as follows:

	Q4/2022	**Q3/2022**	**Q4/2021**
Total sales	$ 396,309	$ 644,832	$ 359,218[1]
Total sales volume	3,067 BOE	6,681 BOE	4,992 BOE
Average realized price per BOE	$ 129.22	$ 96.52	$ 71.96
Petroleum sales	$ 392,716	$ 612,990	$ 325,089
Petroleum sales volume	2,570 BOE	5,763 BOE	4,378 BOE
Average petroleum realized price per BOE	$ 152.81	$ 106.37	$ 74.25
Natural gas sales	$ 3,593	$ 31,842	$ 34,128
Natural gas sales volume	497 BOE	918 BOE	614 BOE
Average natural gas realized price per BOE	$ 7.23	$ 34.69	$ 55.58
Production costs	$ 97,356	$ 384,797	$ 356,833
Average per BOE	$ 31.74	$ 57.60	$ 71.48
Transportation and storage costs	$ 36,408	$ 99,686	$ 70,655
Average per BOE	$ 11.87	$ 14.92	$ 14.15
Royalties	$ (1,385)	$ 38,951	$ 180,166
Average per BOE	$ (0.45)	$ 5.83	$ 36.09
Netback	$ 263,930	$ 121,398	$ (248,436)
Average per BOE	$86.05	$18.17	$ (49.76)

(1) Does not include an adjustment of $479,645 to revenues previously reported by the operator in prior quarters in fiscal 2021.

Q4/2022 Compared to Q3/2022

Total sales revenues decreased by 39%, from $644,832 in Q3/2022 to $396,309 in Q4/2022 primarily due to a 54% decrease in sales volume, from 6,681 BOE in Q3/2022 compared to 3,067 BOE in Q4/2022. The decrease in sales volume is primarily due to the Cheal E-5 well being shut-in for repairs during Q4/2022.

During Q4/2022 operating costs decreased by 75%, from $384,797 in Q3/2022 to $97,356 in Q4/2022 due to unexpected repair costs in Q3/2022.

During Q4/2022 the Company reported net loss of $1,556,610 compared to a net income of $32,263 for Q3/2022. The increase in loss of $1,588,873 is primarily attributed to the following

(i) recognition of a recovery of depletion of $75,824 in Q4/2022 due to the change in the Company's petroleum reserve base at the end of fiscal 2022;
(ii) recognition of a foreign exchange loss of $69,636 in Q4/2022 compared to a foreign exchange loss of $13,567 in Q3/2022;
(iii) recognition of a loss on sale of investments of $22,815 in Q3/2022 compared to $nil in Q4/2022: and
(iv) recognition of an impairment of exploration and evaluation assets for $1,627,056 in Q4/2022.

Q4/2022 Compared to Q4/2021

Total sales revenues increased by $37,091 from $359,218 in Q4/2021 to $396,309 in Q4/2022. The increase is primarily attributed to the increase in the average realized price per BOE from $71.96 in Q4/2021 to $129.22 in Q4/2022.

During Q4/2022 the Company reported net loss of $1,556,610 compared to a net loss of $245,343 for Q4/2022. The increase in loss of $1,311,267 is primarily attributed to:

(i) recognition of a recovery of depletion of $4,435 in Q4/2022 compared to a recovery of depletion of $94,348 in Q4/2021 due to the change in the Company's petroleum reserve base at the end of fiscal 2022 and 2021;

(ii) recognition of a foreign exchange loss of $518,875 in Q4/2021 compared to a foreign exchange gain of $69,636 in Q4/2022;

(iii) recognition of a realized gain on sale of investments in Q4/2021 of $167,604 compared to $nil in Q4/2022 and offset by an unrealized loss on sale of investments of $194,099 in Q4/2021 compared to $nil in Q4/2022; and

(iv) recognition of an impairment of exploration and evaluation assets for $1,627,056 in Q4/2022.

Fiscal 2022 Compared to Fiscal 2021

	Fiscal 2022	**Fiscal 2021**
Total sales	$ 1,753,974	$ 2,443,384
Total volume	19,669 BOE	47,972 BOE
Average realized price per BOE	$ 89.17	$ 50.93
Petroleum sales	$ 1,682,424	$ 2,104,624
Petroleum volume	16,911 BOE	39,608 BOE
Average petroleum realized price per BOE	$ 99.49	$ 53.14
Natural gas sales	$ 71,550	$ 338,759
Natural gas volume	2,758 BOE	8,364 BOE
Average natural gas realized price per BOE	$ 25.94	$ 40.50
Production costs	$ 1,345,059	$ 1,402,875
Average per BOE	$ 68.39	$ 29.24
Transportation and storage costs	$ 264,492	$ 681,687
Average per BOE	$ 13.45	$ 14.21
Royalties	$ 67,324	$ 235,630
Average per BOE	$ 3.42	$ 4.91
Netback	$ 77,099	$ 123,192
Average per BOE	$ 3.92	$ 2.57

Total sales revenues decreased by $689,410, from $2,443,384 in fiscal 2021 to $1,753,974 in fiscal 2022. The decrease was attributable to a 59% decrease in sales volume from 47,972 BOEs during fiscal 2021 to 19,669 BOEs during fiscal 2022. During fiscal 2022 the Cheal-E1 was still not fully producing and the Cheal-E2 well experienced a blockage and stopped producing at the beginning of March 2021. A full workover of both the Cheal-E1 and E-2 wells was not completed until the beginning of August 2021 when both wells were brought back into production. In addition during Q4/2022 the Cheal E-5 well was shut in to awaiting repairs

During fiscal 2022 production costs increased by $39.15 per BOE from $29.24 per BOE in fiscal 2021 to $68.39 during fiscal 2022 reflecting the unexpected repair costs incurred due to the blockages on the Cheal-E1 and Cheal-E2 wells during fiscal 2022. See "Projects Update - New Zealand".

During fiscal 2022 the Company reported a net loss of $2,040,590 compared to a net loss of $584,572 during fiscal 2021. The $1,456,018 increase in loss is primarily attributed to:

(i) recognition of depletion of $169,524 during fiscal 2022 compared to $314,282 during fiscal 2021 due to the change in the Company's petroleum reserve base at the end of fiscal 2022 and 2021;

(ii) a $464,565 decrease in foreign exchange loss from a loss of $489,319 during fiscal 2021 compared to a loss of $24,754 in fiscal 2022;

(iii) partially offset by the recognition of an unrealized gain on investments of $819,578 in fiscal 2021 compared to $nil in fiscal 2022 and offset by a realized loss on sale of investments of $380,026 during fiscal 2021 compared to $22,815 during fiscal 2022 and

(iv) recognition of an impairment of exploration and evaluation assets for $1,627,056 in fiscal 2022.

General and administrative expenses incurred during fiscal 2022 and fiscal 2021 are as follows:

	2022 $	2021 $
Accounting and administrative	36,800	38,100
Audit and related	57,611	62,925
Bank charges	2,553	1,735
Corporate development	2,538	5,878
Insurance	18,921	21,895
Legal	36,624	53,202
Non-deductible interest	-	1,196
Office	1,220	1,960
Professional fees	81,494	99,660
Regulatory fees	7,529	6,944
Shareholder costs	1,562	1,620
Transfer agent fees	6,292	3,801
	253,144	298,916

Specific expenses of note during fiscal 2022 and 2021 are as follows:

(i) professional fees totalling $83,257 were incurred during fiscal 2022 compared to $99,660 during fiscal 2021 of which $42,000 (2021 - $53,000) was paid to directors and officers of the Company and $39,494 (2021 - $46,660) was paid to consultants for administrative and financial services; and

(ii) legal fees of $36,624 were incurred during fiscal 2022 compared to $53,202 during fiscal 2021. During fiscal 2021 the Company incurred significant legal services on the proposed disposition of the New Zealand oil and gas assets

During fiscal 2022 the Company incurred general exploration expenses of $28,494 (2021 - $56,275) of which $18,945 (2021 - $31,448) was related to PEP 54879 and $9,549 (2021 - $24,827) was for ongoing review of current exploration and evaluation assets.

Property, Plant and Equipment

During fiscal 2022 the Company incurred total additions of $86,493 (2021 - $38,022) for the Cheal-East wells and recorded a decrease of $197,550 (2021 - increase of $567,431) in foreign exchange movement for property, plant and equipment additions on the New Zealand properties.

	Petroleum and Natural Gas Properties (PMP 60291) $
Cost:	
Balance at March 31, 2020	13,180,403
Capital expenditures	38,022
Revision of estimate for decommissioning costs	(88,613)
Foreign exchange movement	567,431
Balance at March 31, 2021	13,697,243
Capital expenditures	86,493
Foreign exchange movement	(197,550)
Balance at March 31, 2022	13,586,186

	Petroleum and Natural Gas Properties (PMP 60291) $
Accumulated Depletion and Depreciation and Impairment:	
Balance at March 31, 2020	(12,524,055)
Depletion and depreciation	(314,282)
Foreign exchange movement	(535,264)
Balance at March 31, 2021	(13,373,601)
Depletion and depreciation	(169,524)
Foreign exchange movement	193,364
Balance at March 31, 2022	(13,349,761)
Carrying Value:	
Balance at March 31, 2021	323,642
Balance at March 31, 2022	236,425

Exploration and Evaluation Assets

	PEP 54877 $
Balance at March 31, 2020	1,579,279
Capital expenditures	(5,803)
Foreign exchange movement	67,986
Balance at March 31, 2021	1,641,462
Foreign exchange movement	(14,406)
Impairment	(1,627,056)
Balance at March 31, 2022	-

During fiscal 2022 the Company determined to impair all capitalized expenditures on PEP 54877 and, accordingly, recorded an impairment of $1,627,056. See also "Projects Update - New Zealand".

Financial Condition / Capital Resources

As at March 31, 2022 the Company had working capital of $5,138,429. 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. The Company is assessing its go forward plans with respect to its New Zealand holdings including possible sale of its concessions. The Company is also continuing its discussion on the continued development of the Teremia North Field. There, however, can be no assurances that an agreement will be reached. In addition, 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 as needed. 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.

Commitments

The Company's share of expected exploration and development permit obligations and/or commitments as at March 31, 2022 are approximately $660,000 to be incurred during fiscal 2023 and $16,000 over the next five years. The Company may choose to alter the program, request extensions, reject development costs, relinquish certain permits or farm-out its interest in permits where practical.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements.

Proposed Transactions

The Company has no 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, classification of investments and assumptions used for share-based compensation. Actual results may differ from those estimates. A detailed summary of the Company's critical accounting estimates and sources of estimation is included in Note 3 to the March 31, 2022 audited annual consolidated financial statements.

Changes in Accounting Policies

A detailed summary of the Company's other significant accounting policies is included in Note 3 to the March 31, 2022 audited annual consolidated financial statements.

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. Key management personnel includes those persons having authority and responsibility for planning, directing and controlling the activities of the Company as a whole. The Company has determined that key management personnel consists of members of the Company's Board of Directors and its executive officers.

(a) During fiscal 2022 and 2021 the following amounts were incurred:

	2022 **$**	**2021** **$**
Professional fees - Nick DeMare, Interim CEO, CFO and Director (1)	18,000	25,000
Professional fees - Mark Brown, Director (2)	12,000	12,000
Professional fees - Kevin Haney, Director	12,000	12,000
Professional fees - Ross McElroy, Director (3)	-	4,000
	42,000	53,000

(1) Paid to Chase Management Ltd. ("Chase") a private company owned by Nick DeMare.
(2) Paid to Pacific Opportunities Capital Ltd., a private company controlled by Mark Brown.
(3) Paid to Edge Geological Consulting Inc., a private company owned by Ross McElroy. Mr.McElroy resigned as a director effective August 11, 2020.

As at March 31, 2022 $5,000 (2021 - $3,000) remained unpaid

(b) During fiscal 2022 the Company incurred a total of $36,800 (2021 - $38,100) to Chase Management Ltd. ("Chase"), a private corporation owned by Nick DeMare, for accounting and administration services provided by Chase personnel, excluding Nick DeMare. As at March 31, 2022 $3,000, (2021 - $1,500) remained unpaid.

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 and amounts receivable represents the maximum credit exposure. The Company does not have an allowance for doubtful accounts on its amounts receivable as at March 31, 2022 and 2021 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. As at March 31, 2022, assuming all other variables remain constant, a change of 10% in oil and gas prices would have an effect on net income or loss of $175,000.

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 fiscal 2022 or fiscal 2021 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 categories: FVTPL; amortized cost; fair value through other comprehensive income ("FVOCI"); and other financial liabilities. The carrying values of the Company's financial instruments are classified into the following categories:

Financial Instrument	**Category**	**March 31, 2022 $**	**March 31, 2021 $**
Cash	Amortized cost	5,143,788	5,434,218
Amounts receivable	Amortized cost	38,870	37,225
Investments- common shares	FVTPL	-	28,500
Accounts payable and accrued liabilities	Amortized cost	(355,037)	(400,164)

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 and accounts payable and accrued liabilities approximate their fair value due to their short-term nature. The recorded amounts for investments approximate their fair value. The fair value of investment in common shares under the fair value hierarchy is measured using Level 1 inputs.

Capital Management

The Company manages its capital structure and makes adjustments to it, based on the funds available to the Company, in order to support the acquisition and exploration of petroleum and natural gas properties. The Board of Directors does not establish quantitative return on capital criteria for management, but rather relies on the expertise of the Company's management to sustain development of the business. The Company defines capital that it manages as share capital. The Company will continue to assess new properties and seek to acquire an interest in additional properties if it feels there is sufficient geologic or economic potential and if it has adequate financial resources to do so. Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable.

The Company's share capital is not subject to any external restrictions. The Company has not paid or declared any dividends since the date of incorporation, nor are any currently contemplated. There have been no changes to the Company's approach to capital management during the period.

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 July 29, 2022 there were 89,585,665 outstanding common shares and 2,790,000 share options outstanding with exercise prices ranging from $0.06 to $0.135 per share.