FORM 51-101 F1

EAST WEST PETROLEUM CORP.

Statement of Reserve Data
and Other Oil and Gas Information
for the Fiscal Year Ended
March 31, 2022

Prepared July 29, 2022

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Part 1: Date of Statement

The effective date of the information being provided in this statement of reserves data and other oil and gas information set forth below is April 1, 2022. The information provided herein was prepared between May and July 2022.

References to oil, gas, natural gas liquids, reserves (gross, net, proved, developed, developed producing, developed non-producing, undeveloped), forecast prices and costs, operating costs, development costs, future net revenue and future income tax expenses shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in the National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), the Companion Policy to NI 51-101 and all forms referenced.

All dollar figures are in Canadian dollars unless stated otherwise.

Part 2: Disclosure of Reserves Data

East West Petroleum Corp. and its subsidiaries (the "Company" or "East West") holds a 30% working interest, subject to Crown royalties, in the Cheal E Field within Petroleum Mining Permit ("PMP") 60291, some 809 acres in size, located in the Taranaki Basin, approximately 40 kilometres southeast of New Plymouth, New Zealand. The Company has joint ownership of PMP 60291 with Tamarind Resources Pte. Ltd. ("Tamarind") who is the operator of the permit areas in the Cheal Field. The oil and natural gas reserves and net present values of future net revenue of the PMP 60291 area interest, in which the Company holds a 30% working interest, were evaluated by Sproule International Limited ("Sproule"), an independent qualified reserves evaluator appointed by the Company.

The following tables, are based on information contained in Sproule's report entitled "Evaluation of the P&NG Reserves of East West Petroleum Corp. in New Zealand (As of April 1, 2022)" (the "Sproule Report"), and prepared in accordance with the Canadian Oil and Gas Evaluation Handbook, show the estimated share of the Company's crude oil and natural gas reserves associated with the Company's interests in the Cheal Area and the net present value of estimated future net revenue for these reserves, using forecast prices and costs as indicated. The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Sproule Report. The recovery and reserve estimates of the Company's oil and natural gas reserves stated here are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates stated here. Readers should note that the totals in the following tables may not add due to rounding.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The Company has adopted the standard measure of six thousand cubic feet (6 mcf) to one barrel (1 bbl) when converting natural gas to barrels of oil equivalent or BOE. 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.

Table 1
NI 51-101
Summary of Oil and Gas Reserves
(As of April 1, 2022)
Forecast Prices and Costs

Reserves

Reserves Category	Oil		Natural Gas		Total BOE	
	Light, Medium and Shale		Solution			
	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (Mboe)	Net (Mboe)
New Zealand						
Proved						
Developed Producing	25	23	15	14	28	26
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
Total Proved	**25**	**23**	**15**	**14**	**28**	**26**
Probable	6	6	3	3	6	6
Total Proved Plus Probable	**31**	**29**	**18**	**17**	**34**	**32**
Possible	2	2	1	1	2	2
Total Proved Plus Probable Plus Possible	**33**	**31**	**19**	**18**	**36**	**33**

Values may not add due to rounding.

Reference Item 2.1 of Form 51-101F1

Table 2
NI 51-101
Summary of Net Present Values of Future Net Revenue
(As of April 1, 2022)
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (% Year)					Unit Value Before Income Tax Discounted at 10%/Year
	0 (M$CDN)	5 (M$CDN)	10 (M$CDN)	15 (M$CDN)	20 (M$CDN)	0 (M$CDN)	5 (M$CDN)	10 (M$CDN)	15 (M$CDN)	20 (M$CDN)	at 10% ($CDN/boe)
New Zealand											
Proved											
Developed Producing	84	115	141	165	186	84	115	141	165	186	5.11
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**84**	**115**	**141**	**165**	**186**	**84**	**115**	**141**	**165**	**186**	**5.11**
Probable	138	142	146	148	150	138	142	146	148	150	22.55
Total Proved Plus Probable	**222**	**257**	**287**	**313**	**335**	**222**	**257**	**287**	**313**	**335**	**8.42**
Possible	154	145	138	132	126	154	145	138	132	126	74.14
Total Proved Plus Probable Plus Possible	**375**	**402**	**426**	**444**	**461**	**375**	**402**	**426**	**444**	**461**	**11.83**

Values may not add due to rounding.

Table 3 NI 51-101 Total Future Net Revenue (Undiscounted) (As of April 1, 2022) Forecast Prices and Costs								
Reserves Category	**Revenue (MCDN$)**	**Royalties (MCDN$)**	**Operating Costs (MCDN$)**	**Development Costs (MCDN$)**	**Well Abandonment/ Other costs Costs (MCDN$)**	**Future Net Revenue Before Income Tax (MCDN$)**	**Income Taxes (MCDN$)**	**Future Net Revenue After Income Taxes (MCDN$)**
New Zealand								
Total Proved	3,000	225	1,970	-	721	84	-	84
Total Proved Plus Probable	3,667	266	2,458	-	721	222	-	222
Total Proved Plus Probable Plus Possible	3,867	284	2,487	-	721	375	-	375

Reference Item 2 of Form 51-101 F1

Values may not add due to rounding.

Table 4 NI 51-101 Net Present Value of Future Net Revenue by Production Group (As of April 1, 2022) Forecast Prices and Costs			
Reserves Category	**Production Group**	**Future Net Revenue Before Income Tax Discounted at 10% per Year (M$US)**	**Unit Value Before Income Tax Discounted at 10% per Year ($US/boe)**
New Zealand			
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	141	1.65
	TOTAL	**141**	**1.65**
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	287	2.78
	TOTAL	**287**	**2.78**
Proved Plus Probable Plus Possible	Light and Medium Crude Oil (including solution gas and associated by-products)	425	11.83
	TOTAL	**425**	**11.83**

Reference Item 2 of Form 51-101 F1

Unit Values are based on net reserve volumes. Hedging revenue included with light/medium oil revenues and unit values

BOE Equivalent 6 Mcf = 1 BOE

Values may not add due to rounding

Part 3: Pricing Assumptions

Forecast benchmark reference price and inflation rate assumptions are summarized in Table 5. This summary table identifies benchmark reference oil pricing schedules that might apply to a *reporting issuer*. Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale. These prices and pricing assumptions were provided to the Company by its independent reserves evaluators, Sproule.

Table 5
NI 51-101
Summary of Pricing and Inflation Rate Assumptions
As of March 31, 2022
Forecast Prices and Costs (1)

Year	WTI Cushing Oklahoma 40° API ($US/bbl)	UK Brent 38° API ($US/bbl)	Operating Cost Inflation Rate(2) (%/Yr)	Capital Cost Inflation Rate (%/Yr)	Exchange Rate(3) ($US/$CDN)	Exchange Rate(3) ($US/$NZ)
Historical						
2017	50.95	54.83	1.7%	2.4%	0.77	0.71
2018	64.77	71.53	2.4%	4.2%	0.77	0.69
2019	57.02	64.17	-0.7%	0.4%	0.75	0.66
2020	39.40	43.21	-5.0%	-5.0%	0.75	0.65
2021	67.91	70.79	3.3%	6.6%	0.80	0.70
Forecast						
2022	93.00	95.00	0.0%	0.0%	0.80	0.64
2023	83.00	85.00	2.0%	2.0%	0.80	0.67
2024	73.00	75.00	2.0%	2.0%	0.80	0.67
2025	74.46	76.50	2.0%	2.0%	0.80	0.67
2026	75.95	78.03	2.0%	2.0%	0.80	0.67
2027	77.47	79.59	2.0%	2.0%	0.80	0.67
2028	79.02	81.18	2.0%	2.0%	0.80	0.67
2029	80.60	82.81	2.0%	2.0%	0.80	0.67
2030	82.21	84.46	2.0%	2.0%	0.80	0.67
2031	83.85	86.15	2.0%	2.0%	0.80	0.67
2032	85.53	87.87	2.0%	2.0%	0.80	0.67
Escalation Rate of 2.0% thereafter						

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting costs only. Prices inflated at 2% where applicable.
(3) Exchange rates used to generate the benchmark reference prices in this table

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.
Reference Item 3 of Form 51-101F1

For the financial year ended March 31, 2022 the Company's weighted average price received for oil was CDN $99.49 per barrel and for natural gas was CDN $4.32 per Mcf.

Part 4: Reconciliations of Changes in Reserves

Reserves Reconciliation

Changes are for reserves in PMP 60291, located in the Taranaki Basin of New Zealand, in which the Company holds a 30% working interest.

Light and Medium Crude Oil	March 31, 2021	March 31, 2022	Change
Gross Proved	60 Mbbl	25 Mbbl	- 35 Mbbl
Gross Probable	18 Mbbl	6 Mbbl	- 12 Mbbl
Gross Proved Plus Probable	78 Mbbl	31 Mbbl	- 47 Mbbl
Conventional Natural Gas	March 31, 2021	March 31, 2022	Change
Gross Proved	37 MMcf	15 MMcf	- 22 MMcf
Gross Probable	11 MMcf	3 MMcf	- 8 MMcf
Gross Proved Plus Probable	48 MMcf	18 MMcf	- 30 MMcf

Table 6
NI 51-101
Reconciliation of Company Gross(1) Reserves (Before Royalty)
by Product Type
(As of April 1, 2022)
Forecast Prices and Costs

	Light and Medium Oil			Solution Gas			Barrel of Oil Equivalent		
Factors	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**
Product Type Transfer	0	0	-	0	0	0	0	0	0
Drilling Extensions	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
Infill Drilling	0	0	0	0	0	0	0	0	0
Technical Revisions	(30)	(16)	(47)	(14)	(10)	(24)	(33)	(18)	(51)
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
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) Gross Reserves presented here are the Company's working interest reserves before deduction of royalties.

BOE Equivalent 6Mcf = 1 BOE   Values may not add due to rounding   Reference: Item 4 of Form 51-101F1

The changes to the reserves estimates can be attributed to those factors set out in Table 6, which are based on a number of factors that includes natural declines from production, revised projected future well performance, production during fiscal 2022 and revised oil price forecast. The technical revisions include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.

Part 5: Additional Information Relating to Reserves Data

Undeveloped Reserves

The Company had no new proved undeveloped reserves in fiscal 2022, 2021 or 2020

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations and meeting the confidence criteria for the Proved Reserves category, where a significant capital expenditure (such as the cost of drilling a well) is required to render them capable of production

The following tables set forth the gross probable undeveloped reserves from the Company's current net interest in New Zealand that were first attributed for each of the Company's product types for the most recent three financial years.

Probable Undeveloped Reserve Vintage

	Light and Medium Oil (Combined)		Conventional Natural Gas Solution Gas		Total Equivalent	
	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (MMcf)	Booked Gross (MMcf)	First Attributed Gross (MBOE)	Booked Gross (MBOE)
March 31, 2020	0.0	0.0	0	0	0	00.0
March 31, 2021	0.0	0.0	0	0	0	00.0
March 31, 2022	0.0	0.0	0	0	0	00.0

The Company's probable undeveloped reserves are those reserves that are expected to be recoverable based on analogy to other wells in the area, seismic interpretations and geological mapping.

Significant Factors or Uncertainties

Aside from the potential impact of material fluctuations in commodity prices, other significant factors or uncertainties that may affect the Company's reserves or the future net revenue associated with such reserves include:

- material changes to existing taxation or royalty rates and/or regulations;
- the United States and New Zealand currency exchange rates relative to the Canadian dollar;
- the timing of completion and level of success of PMP 60291 that includes the drilling success of future production wells; and
- the ability to obtain storage and sales contracts for crude oil and natural gas.

Future Development Costs

The following table summarizes the Company's portion of estimated development costs deducted in the estimation of reserves data disclosed in Item 2 and can be attributed as follows:

Company Annual Capital Expenditures

Fiscal Year	Total Proved (Cdn $)	Total Proved Plus Probable (Cdn $)	Total Proved Plus Probable Plus Possible (Cdn $)
2023	0	0	0
2024	0	0	0
2025	0	0	0

Currently the Company does not have any future economic development activities, scheduled for development within the next three years.

Part 6: Other Oil and Gas Information

Oil and Gas Properties and Wells

On December 11, 2012, New Zealand Petroleum and Minerals (“NZP&M”), awarded TAG Oil Ltd. (“TAG”) four onshore exploration permits offered in New Zealand’s 2012 blocks offer program, which included the Cheal East Permit and the Cheal South Permit. The award of these permits led to the creation of a joint venture with East West in which TAG operates the permits. East West has a 30% working interest in PMP 60291 and did have a 50% working interest in PEP 54879. In June 2017 the joint venture submitted the PEP 54879 permit, in which the Company had a 50% working interest, to be relinquished. On August 4, 2017 NZP&M approved the surrender of the PEP 54879. The development of the Cheal East Permit commenced with the initial permit work program, which included drilling five shallow exploration wells (the Cheal-E1, E2, E3, E4, and E5 wells) that were successfully completed during the third quarter of fiscal 2014. On May 16, 2015, TAG completed the pipeline construction connecting the Cheal E-Site Production Facility to the Cheal Production Facility, which was fully operational and flowing gas ahead of schedule. The pipeline allows the Operator to significantly reduce operating costs while generating additional revenues by selling previously flared gas, and gives the Operator the ability to quickly monetize future oil and gas wells drilled in the Cheal East Permit. On October 31, 2016, TAG submitted an application to NZP&M to convert the Cheal East Permit from a petroleum exploration permit to a petroleum mining permit. The mining permit (PMP 60291) was granted on September 15, 2017 and has been carved out of the existing exploration permit (PEP 54877). The duration of part of the remaining PEP 54877 acreage was extended for an additional five-year term, commencing December 11, 2017 (ending December 17, 2022). In September 2019, TAG completed a definitive share and asset purchase agreement with Tamarind Resources Pte. Ltd. (“Tamarind”), to sell substantially all of its Taranaki Basin assets and operations in New Zealand which included TAG’s interest in PMP 60291. At that time Tamarind became the Company’s joint venture partner and the Operator of PMP 60291.

Currently, PMP 60291, in which the Company has a 30% working interest, is the Company’s only property with attributed reserves and is located in the onshore portion of New Zealand’s Taranaki Basin located along the west coast of the North Island. The wells produce from shallow Miocene reservoirs. The reservoirs are confined to lithologically sealed sand bodies accumulated as submarine channels and fan deposits on a lower slope to the basin floor. The shallow Miocene wells are providing steady oil production that generate cash flow and, as expected, more predictable decline rates. The shallow wells now on production are utilizing good oil field practice. The Operator will continue to optimize production methods, through programs such as water-flooding, and perform planned routine maintenance on a regular basis, which requires certain wells to be shut-in periodically.

The PMP 60291 produces oil and solution gas from the Mount Messenger and Urenui formations, with a reported quality of between 36 and 42 degrees API and 1576 Btu/scf using artificial lift and is under primary recovery. Oil and gas production commenced in November 2013, with 4 wells currently producing and one well (Cheal-E5) shut-in pending a pump repair. The average daily oil production rate in March 2022 was approximately 204 bopd with an average gas-oil-ratio of 665 scf/bbl (raw).

The well Cheal-E7, drilled from the E pad into PMP 38156, immediately adjacent to PMP 60291, was converted to water injection into the Mount Messenger 3 sand in March 2017 but no reserves have been assigned for secondary recovery as the Company does not hold an interest in the Cheal-E7 well.

The Cheal E pad contains test separation and metering facilities. The sale of the Company’s gas production from PMP 60291 occurs at the point the production enters the pipeline at the Cheal E pad. The sale of the Company’s oil production from PMP 60291 occurs on loading of crude on ships at the Operator’s port loading facilities.

Wells Cheal-E1, Cheal-E2, Cheal-E5 (currently awaiting repair), Cheal-E6 and Cheal-E8 are the producing wells. As part of the overall waterflood development project, the Cheal-E4 well was identified as a future water injector and the injection conversion was completed with additional perforations added to the MM4 zone with water injection commencing in August 2018. Well Cheal-E3 has never been put on production.

During the fourth quarter of fiscal 2017, execution of the second phase of the enhanced recovery waterflood project at the Cheal East Permit commenced by converting the Cheal-E7 well into a water injection well.

The development plan of the field considers production from existing wells with reservoir pressure support through water injection.

Secondary recovery operations have commenced with the initiation of water injection into the adjacent Cheal E-7 well and the Cheal E-4 well, but no incremental volumes have been assigned due to the lack of analogue waterflood data in the Taranaki Basin and no demonstrated results to date.

As of the effective date there is one well Cheal-E5 capable of production that is not producing and is scheduled for remedial work. Remedial work should be completed by the Company's second or third quarter. The producing rate or incremental rate for each of these wells, as the case may be, has been assigned based on the previous well capability. Although this remedial work is planned, it is uneconomic from a reserves perspective and thus non-producing volumes have not been included in the reserves evaluation.

The following table summarizes the wells drilled to date as at March 31, 2022 on PMP 60291 in New Zealand:

Producing - Pumping Oil		**Non-Producing - Shut-In or Water Injector**	
Gross	Net	Gross	Net
5.0	1.5	2.0	0.6

Properties with No Attributed Reserves

The following table summarizes the Company's interests at March 31, 2022 in properties located in New Zealand that have no attributed reserves:

Permit	**Location**	**Working Interest**	**Gross Acres**	**Net Acres**
PEP 54877	Taranaki Basin (Onshore)	30%	3,065	920
Total			**3,065**	**920**

The Company has $nil work commitments for PEP 54877 as of March 31, 2022.

The joint venture plans to continue to maintain its key permits in good standing with the Ministry of Economic Development in New Zealand and, where necessary, lodge additional term applications accordingly.

PEP 54877 is scheduled to expire December 17, 2022. The Operator does not intend to proceed with a renewal as a detailed prospectivity review was undertaken and the forecasted economic prospects of PEP 54877 does not meet the Operator's internal risk criteria.

Forward Contracts

The Company does not have any forward contracts. However, the Company through its PMP 60291 joint venture with Tamarind, is a party to oil sales contracts. Gas produced at PMP 60291 is sold pursuant to a gas supply contract between Tamarind and an independent third party.

The principal markets for the sale of oil produced at PMP 60291 are in the Australasian region. More specifically, the oil that is produced from PMP 60291 is exported to the Australasian markets in accordance with oil sales contracts.

Tax Horizon

The Company was not required to pay income taxes in New Zealand for its most recently completed financial year. The Company does not anticipate paying income taxes in the fiscal year 2023 due to the immediate allowable deductions for exploration expenditure as prescribed by New Zealand tax regulations.

Costs Incurred

In the year ended March 31, 2022, the Company made the following expenditures (whether capitalized or charged to expense):

Country - New Zealand	
Property Acquisition Costs - Proved Properties	$ nil
Property Acquisition Costs - Unproved Properties	$ nil
Exploration Costs	$ nil
Development Costs	$ 86,493

Exploration and Development Activities

The Company completed the following wells during the year ended March 31, 2022 in which the Company has a 30% working interest:

	Exploratory Wells Completed in New Zealand		**Development Wells Completed in New Zealand**	
Well Type	**Gross**	**Net**	**Gross**	**Net**
Oil	-	-	-	-
Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry Holes	-	-	-	-

No new wells were developed on the Company's land holdings during fiscal 2022. For further detail of the Company's exploration and development activities for the 2022 fiscal year and as at the date of this statement, please refer to the heading "Part 6 Other Oil and Gas Information - Oil and Gas Properties and Wells" and "Part 6 Other Oil and Gas Information - Properties with No Attributed Reserves".

Production Estimates

Estimated production volumes for fiscal 2023 are derived from gross proved reserves and gross probable reserves associated with PMP 60291 and disclosed under Part 2. The figures represent East West's working interest before deductions:

Cheal East Field New Zealand
Estimated Production Volumes for Fiscal 2023

Product Type	**Gross Proved**	**Gross Probable**
Light and medium oil (bbl)	19,344	822
Conventional natural gas (MMcf)	11.1	0.5

Production History

The Company’s historical sales production and netback data in New Zealand for the year ended March 31, 2022 is presented below:

	Q1	Q2	Q3	Q4	Total Fiscal 2022
Company share of daily sales production					
- Light and Medium Crude Oil (bbl/d)	36	58	63	29	46
- Conventional Natural Gas (Mcf/d)	27	61	60	33	45
Average (CDN $/ BOE)					
- Price received	$ 78.60	$ 67.86	$ 96.52	$ 129.22	$ 89.17
- Royalties	$ 3.08	$ 2.95	$ 5.83	$ (0.45)	$ 3.42
- Transportation and Storage	$ 13.86	$ 12.40	$ 14.92	$ 11.87	$ 13.45
- Production Costs	$ 152.81	$ 47.99	$ 57.60	$ 31.74	$ 68.39
- Netback	$ (91.14)	$ 4.51	$ 18.17	$ 86.05	$ 3.92
Company share of 2022 sales - BOE sold	3,690	6,231	6,681	3,067	19,669