2024 REPORTING PACKAGE

March 20, 2025

AIM: PTAL
TSX: TAL
OTCQX: PTALF

PetroTal

PetroTal Announces Q4 and Full Year 2024 Results

Calgary, AB and Houston, TX – **March 20, 2025** – PetroTal Corp. ("PetroTal" or the "Company") (TSX: TAL, AIM: PTAL and OTCQX: PTALF) is pleased to report its operating and financial results for the three months and year ended December 31, 2024. All amounts herein are in United States dollars unless stated otherwise.

Key Highlights

- Average Q4 2024 sales and production of 19,087 and 19,142 barrels of oil per day ("bopd"), respectively, including volumes from the acquisition of Block 131, which closed in late November;
- Average FY 2024 sales and production of 17,558 bopd and 17,785 bopd, respectively, slightly above the guidance range (16,500 to 17,500 bopd), and an increase of approximately 25% relative to 2023 average production;
- Group production has averaged approximately 23,200 bopd in 2025 YTD;
- Generated EBITDA of $40.2 million ($22.86/bbl) and $237 million ($36.87/bbl) in Q4 2024 and FY 2024 respectively, near the high end of annual guidance ($200 to 240 million);
- Development capital expenditures ("capex") totaled $50.6 million in Q4 2024 and $163 million in FY 2024, near the midpoint of the annual guidance range ($150-175 million);
- Annual free funds flow was $74.1 million, prior to returns of capital to shareholders, representing a yield of approximately 21% relative to our year-end 2024 market capitalization;
- Available cash increased to $103 million at year-end 2024 (from $91 million the prior year);
- On March 14, PetroTal paid a dividend of $0.015/share, associated with Q4 2024 results. This was PetroTal's eighth consecutive quarterly dividend, bringing total return of capital under the Company's dividend program to $116 million ($0.14/share);
- PetroTal paid total dividends of $0.06/share and repurchased 11.3 million common shares in 2024, representing approximately $65 million of total capital returned to shareholders (compared to $62 million in 2023).
- Successfully completed seven new oil wells in 2024. During 2024, six of these oil wells produced just over 2 million bbls of oil and generated approximately $85 million in net operating income, which amounts to a 100% return of investment as of year-end 2024.

Selected financial and operational information outlined above should be read in conjunction with the Company's unaudited consolidated financial statements and management's discussion and analysis ("MD&A") for the three and twelve months ended December 31, 2024, which are available on SEDAR+ at www.sedarplus.ca and on the Company's website at www.PetroTal-Corp.com.

(1) Non-GAAP (defined below) measure that does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities. See "Selected Financial Measures" section.

Manuel Pablo Zuniga-Pflucker, President and Chief Executive Officer, commented:

"PetroTal reported strong financial and operational results in 2024, increasing our production by an average of 25% over 2023, while returning more than $65 million to shareholders through dividends and share buybacks. The Company also successfully managed a period of record low river levels during the dry season, on our way to exceeding annual production guidance.

2025 is off to an excellent start, with the results of our development drilling campaign and facility investments supporting year-to-date average production of more than 23,000 bopd. We are also excited to commence development on our new asset at the Los Angeles field, along with the greater Block 131 region, with a new drilling rig expected to arrive around mid-year.

Over the past eight months, PetroTal has been actively hedging its 2025 production volumes and has no long-term debt or significant drilling commitments. We are committed to our ongoing capital program which prioritizes a material dividend in tandem with strategic initiatives that include Block 131 development and the erosion control project. I would like to thank shareholders for their continued support, as well as PetroTal's board of directors and the rest of the PetroTal team for their continued valuable contributions to our success"

Selected Financial Highlights

	Three Months Ended				Twelve Months Ended			
	Q4-2024		Q3-2024		Q4-2024		Q4-2023	
	$/bbl	$ 000	$/bbl	$ 000	$/bbl	$ 000	$/bbl	$ 000
Average Production (bopd)		19,142		15,203		17,785		14,248
Average sales (bopd)		19,087		14,760		17,558		14,421
Total sales (bbls)[1]		1,756,030		1,357,961		6,426,106		5,263,485
Average Brent price	$73.42		$77.74		$78.98		$81.53	
Contracted sales price, gross	$73.16		$78.58		$79.15		$80.54	
Tariffs, fees and differentials	($21.10)		($20.52)		($20.96)		($20.33)	
Realized sales price, net	$52.06		$58.06		$58.19		$60.21	
Oil revenue[1]	$52.06	$91,421	$58.06	$78,850	$58.19	$373,940	$60.21	$316,911
Royalties[2]	$7.42	$13,022	$5.47	$7,433	$6.22	$39,947	$5.82	$30,648
Operating expense	$7.88	$13,843	$8.23	$11,176	$6.90	$44,320	$6.16	$32,446
Direct Transportation:								
Diluent	$0.14	$248	$0.90	$1,218	$0.77	$4,931	$1.30	$6,857
Barging	$1.89	$3,317	$0.68	$927	$0.96	$6,200	$0.66	$3,475
Diesel	$0.05	$81	$0.13	$173	$0.08	$520	$0.10	$516
Storage	$1.97	$3,452	$0.51	$690	$0.58	$3,697	$0.78	$4,115
Total Transportation	$4.05	$7,098	$3.05	$3,008	$2.39	$15,348	$2.84	$14,963
Net Operating Income[3,4]	$32.71	$57,458	$42.14	$57,233	$42.68	$274,325	$45.39	$238,854
Erosion Control	$5.45	$9,569	$0.40	$548	$1.57	$10,117	$0.00	$0.00
G&A	$4.86	$8,534	$6.75	$9,160	$5.65	$36,291	$5.33	$28,049
EBITDA[3]	$22.41	$39,355	$34.20	$46,406	$35.47	$227,917	$40.05	$210,805
Adjusted EBITDA[3,5]	$22.87	$40,167	$35.69	$48,436	$36.88	$236,972	$40.97	$215,646
Net Income	$12.10	$21,242	$4.46	$7,179	$17.34	$111,450	$21.00	$110,505
Basic Shares Outstanding (000)		911,783		913,259		911,783		912,314
Market Capitalization[6]		$355,595		$429,231		$355,595		$556,511
Net Income/Share ($/share)		$0.02		$0.01		$0.11		$0.12
Capex		$50,589		$43,019		$162,827		$108,454
Free Funds Flow[3] [7]	($11.02)	($10,422)	$4.81	$6,537	$11.56	$74,145	$20.37	$107,192
% of Market Capitalization[6]		(2.9%)		1.2%		20.9%		19.3%
Total Cash[8]		$114,528		$133,072		$114,528		$111,299
Net Surplus (Debt) [3] [9]		($1,532)		$10,124		($1,532)		$52,307

1. Approximately 89% of Q4 2024 sales were through the Brazilian route vs 89% in Q3 2024.
2. Royalties include the impact of the 2.5% community social trust.
3. Non-GAAP (defined below) measure that does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures presented by other entities. See “Selected Financial Measures” section.
4. Net operating income represents revenues less royalties, operating expenses, and direct transportation.
5. Adjusted EBITDA is net operating income less general and administrative (“G&A”) and plus/minus realized derivative impacts.
6. Market capitalization for Q4 2024, Q3 2024 and Q4 2023 assume share prices of $0.39, $0.47, and $0.61 respectively on the last trading day of the quarter.
7. Free funds flow is defined as adjusted EBITDA less capital expenditures. See “Selected Financial Measures” section.
8. Includes restricted cash balances.
9. Net Surplus (Debt) = Total cash + all trade and net VAT receivables + short and long term net derivative balances – total current liabilities – long term debt – non current lease liabilities – net deferred tax – other long term obligations.

Q4 2024 Financial Variance Summary

US$/bbl Variance Summary	Three months ended Q4 2024	Q3 2024	Variance	Twelve months ended Q4 2024	Q4 2023	Variance
Oil Sales (bopd)	**19,087**	**14,760**	**4,327**	**17,558**	**14,421**	**3,137**
Contracted Brent Price	**$73.42**	**$77.74**	**($4.32)**	**$78.98**	**$81.53**	**($2.55)**
Realized Sales Price	**$52.06**	**$58.06**	**($6.00)**	**$58.19**	**$60.21**	**($2.02)**
Royalties	$7.42	$5.47	$1.95	$6.22	$5.82	$0.40
Total OPEX and Transportation	$11.93	$10.45	$1.48	$9.29	$9.00	$0.29
Net Operating Income[1,2]	**$32.71**	**$42.14**	**($9.43)**	**$42.68**	**$45.39**	**($2.71)**
G&A	$4.86	$6.75	($1.89)	$5.65	$5.33	$0.32
EBITDA	**$22.41**	**$34.20**	**($11.79)**	**$35.47**	**$40.05**	**($4.58)**
Net Income	$12.10	$4.46	$7.64	$17.34	$21.00	($3.66)
Free Funds Flow[1,3]	**($11.02)**	**$4.81**	**($15.83)**	**$11.56**	**$20.37**	**($8.81)**

- Sales volumes increased by 29% QoQ, due to the conclusion of dry season in the Amazon basin, which removed constraints on PetroTal's ability to export crude oil from the Bretana field. FY 2024 sales volumes increased by 22% relative to 2023, due to an active development drilling program and ongoing expansion of export capacity;
- Brent oil prices declined by $4.32/bbl in Q4, and $2.55/bbl in FY 2024, relative to the comparable periods in 2023. PetroTal's realized sale price declined by $6.00/bbl in Q4 2024, primarily due to the timing of export sales during the quarter. However, relative to FY 2023, the Company's realized sale price declined less than the Brent benchmark;
- Operating and transportation expenses increased by $1.48/bbl in Q4 2024, mainly due to demurrage charges on the Company's barge fleet. However, on a YTD basis, operating and transportation costs have risen by a marginal $0.29/bbl;
- Net income rose by $7.64/bbl in Q4 2024, mainly due to an unrealized derivative gain of $2.7 million, and a gain related to deferred income tax expense.

1. See "Selected Financial Measures".
2. Net operating income represents revenues less royalties, operating expenses, and direct transportation.
3. Free funds flow is defined as adjusted EBITDA less capital expenditures.
4. Net Surplus (Debt) = Total cash + all trade and net VAT receivables + short and long term net derivative balances – total current liabilities – long term debt – non current lease liabilities – net deferred tax – other long term obligations.

Additional financial and operational updates during and subsequent to the quarter ending December 31, 2024:

Production & Drilling Update

PetroTal's 2025 year-to-date production has averaged approximately 23,200 bopd, including 22,600 bopd from the Bretana field and 600 bopd from the Los Angeles field. With river levels comfortably above the historical average during the ongoing rainy season, PetroTal is currently exporting from the Bretana field near the capacity of its barge fleet. Production also remains constrained by facility capacity, as the Company awaits the installation of CPF4, which will increase oil handling capacity to 32,000 bopd by mid-year.

The Company continues to observe strong production response from recently drilled wells; the 22H well was brought onstream in mid-January and averaged 4,500 bopd over its first 30 days onstream, including a maximum daily rate of 7,025 bopd. Well 23H was brought onstream for production testing in the last week of February 2025, flowing naturally at an average of 3,500 bopd over its first ten days onstream. Flush production from wells 22H and 23H is expected to be sufficient to support production levels throughout H1 2025, in advance of the annual dry season which typically sets in by August.

Erosion Control Project

PetroTal has demobilized its drilling rig at Bretana and is preparing to ramp up activity on the erosion control project in Q2 2025. Transportation of the preassembled steel segments from the project's staging point in Pucallpa is expected to take place in May, when the jackup is also expected to arrive on site. The Company should be in a position to provide additional updates on the project with Q1 2025 results in mid-May.

As previously disclosed, PetroTal recorded a $9.6 million expense for the erosion control project in Q4 2024, primarily associated with the purchase of steel components. The Company continues to budget $35-40 million for the erosion control project in 2025, approximately 75% of which will be expensed through the income statement.

Cash and Liquidity Update

PetroTal ended 2024 with a total cash position of $114.5 million, of which $102.8 million was unrestricted. This compares to total cash of $133 million at the end of Q3 2024, and $111 million at the same time last year. Net Surplus, a non-IFRS measure which PetroTal uses to describe its liquidity position net of working capital and various non-current liabilities, declined to a deficit of $1.5 million at the end of Q4 2024. This compares to a surplus of $10.1 million at the end of Q3 2024, and $52 million at the end of 2023. The main source of variance in net surplus relative to the prior quarter is the lease liability associated with PetroTal's acquisition of a drilling rig in Q4 2024. Relative to year-end 2023, PetroTal has also recorded a large increase in tax liabilities as the Company consumed net operating losses over the prior three years.

PetroTal entered into additional hedge agreements during Q4 2024, and subsequently in January 2025. The Company now has hedges on an average of 260,000 barrels per month over the next twelve months, which represents approximately 40% of forecast production volumes. The terms of the hedge agreements entered into during Q4 2024 and January 2025 are essentially the same as those reported with Q3 2024 results in November. PetroTal's hedges consist of costless collars with a Brent floor price of $65.00/bbl and a ceiling of $82.50/bbl, with a cap of $102.50/bbl.

Shareholder Returns Update

As previously announced on February 20, 2025, PetroTal declared a quarterly dividend of $0.015 per share, associated with Q4 2024 results. This dividend was paid on March 14 to shareholders of record as of February 28, bringing cumulative payout under the Company's ongoing dividend program to $116 million. PetroTal's 2025 liquidity strategy prioritizes dividend sustainability, balanced with Block 131 development and erosion control working capital requirements. As a result, the volume of share buybacks has decreased compared to previous quarters. The Company will continue to monitor buyback levels and will operate in the quarterly approved bandwidths announced in May 2024.

2025 Budget Guidance

As previously announced on January 16, 2025, PetroTal has guided to annual average production of 21,000 to 23,000 bopd in 2025, an increase of approximately 24% relatively to 2024. At an annual average Brent oil price of $75.00/bbl, this production is expected to drive annual EBITDA of $240 to 250 million, supported by capital investments of $140 million. As of March 20, 2025 PetroTal is pleased to report no material changes to its forecast.

Year-end 2024 Reserves

On February 19, 2025, PetroTal announced its updated reserves evaluation for the year ending December 31, 2024. The Company reported growth in all major reserves categories, with its 2P after tax reserves value per share increasing to $1.89/share. The after tax net present value of PetroTal's reserves, discounted at 10% ("NPV10"), increased to $1.7 billion, on associated 2P reserves of 114 million bbls. The Company successfully replaced 293% and 208% of 1P and 2P reserves, respectively, with an associated 2P reserve life index of 13 years. For the full text of this announcement, please refer to PetroTal's press release dated February 20, 2025, filed on SEDAR+ (www.sedarplus.ca) and posted on PetroTal's website (www.petrotalcorp.com). In addition to the summary information disclosed in this press release, more detailed information will be included in the annual information form for the year ended December 31, 2024, to be filed on SEDAR+ (www.sedarplus.ca) and posted on PetroTal's website (www.petrotalcorp.com) by March 28, 2025.

Corporate Presentation Update

The Company has updated its Corporate Presentation, which is available for download or viewing at www.petrotalcorp.com.

Q4 2024 Webcast on March 20, 2025

PetroTal's management team will host a webcast to discuss Q4 2024 results on March 20, 2025 at 9am CT (Houston) and 2pm GMT (London). Please see the link below to register.

https://stream.brrmedia.co.uk/PTAL_Q4_2024

ABOUT PETROTAL

PetroTal is a publicly traded, tri-quoted (TSX: TAL, AIM: PTAL and OTCQX: PTALF) oil and gas development and production Company domiciled in Calgary, Alberta, focused on the development of oil assets in Peru. PetroTal's flagship asset is its 100% working interest in the Bretaña Norte oil field in Peru's Block 95, where oil production was initiated in June 2018. In early 2022, PetroTal became the largest crude oil producer in Peru. The Company's management team has significant experience in developing and exploring for oil in Peru and is led by a Board of Directors that is focused on safely and cost effectively developing the Bretaña oil field. It is actively building new initiatives to champion community sensitive energy production, benefiting all stakeholders.

For further information, please see the Company's website at www.petrotal-corp.com, the Company's filed documents at www.sedarplus.ca, or below:

Camilo McAllister
Executive Vice President and Chief Financial Officer
Cmcallister@PetroTal-Corp.com
T: (713) 253-4997

Manolo Zuniga
President and Chief Executive Officer
Mzuniga@PetroTal-Corp.com
T: (713) 609-9101

PetroTal Investor Relations
InvestorRelations@PetroTal-Corp.com

Celicourt Communications
Mark Antelme / Jimmy Lea
petrotal@celicourt.uk
T : +44 (0) 20 7770 6424

Strand Hanson Limited (Nominated & Financial Adviser)
Ritchie Balmer / James Spinney / Robert Collins
T: +44 (0) 207 409 3494

Stifel Nicolaus Europe Limited (Joint Broker)
Callum Stewart / Simon Mensley / Ashton Clanfield
T: +44 (0) 20 7710 7600

Peel Hunt LLP (Joint Broker)
Richard Crichton / David McKeown / Georgia Langoulant
T: +44 (0) 20 7418 8900

READER ADVISORIES

FORWARD-LOOKING STATEMENTS: This press release contains certain statements that may be deemed to be forward-looking statements. Such statements relate to possible future events, including, but not limited to: oil production levels and production capacity, including wells 22H and 23H; PetroTal's 2025 development program for drilling, completions and other activities, including Block 131 and CPF-4 at Bretana; plans and expectations with respect to the erosion control project; and PetroTal's expectations with respect to dividends and share buybacks. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "expect", "plan", "estimate", "potential", "will", "should", "continue", "may", "objective", "intend" and similar expressions. The forward-looking statements provided in this press release are based on management's current belief, based on currently available information, as to the outcome and timing of future events. The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, the ability to obtain and maintain necessary permits and licenses, the ability of government groups to effectively achieve objectives in respect of reducing social conflict and collaborating towards continued investment in the energy sector, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labour, royalty regimes and exchange rates, the impact of inflation on costs, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, future river water levels, the Company's growth strategy, general economic conditions and availability of required equipment and services. PetroTal cautions that forward-looking statements relating to PetroTal are subject to all of the risks, uncertainties and other factors, which may cause the actual results, performance, capital expenditures or achievements of the Company to differ materially from anticipated future results, performance, capital expenditures or achievement expressed or implied by such forward-looking statements. Factors that could cause actual results to differ materially from those set forth in the forward-looking statements include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks), business performance, legal and legislative developments including changes in tax laws and legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures, credit ratings and risks, fluctuations in interest rates and currency values, changes in the financial landscape both domestically and abroad, including volatility in the stock market and financial system, wars (including Russia's war in Ukraine and the Israeli-Hamas conflict), regulatory developments, commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry, changes in the financial landscape both domestically and abroad (including volatility in the stock market and financial system) and the occurrence of weather-related and other natural catastrophes. Readers are cautioned that the foregoing list of factors is not exhaustive. Please refer to the annual information form for the year ended December 31, 2023 and the management's discussion and analysis for the three months ended March 31, 2024 for additional risk factors relating to PetroTal, which can be accessed either on PetroTal's website at www.petrotal-corp.com or under the Company's profile on www.sedarplus.ca. The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

OIL REFERENCES: All references to "oil" or "crude oil" production, revenue or sales in this press release mean "heavy crude oil" as defined in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

SHORT TERM RESULTS: References in this press release to peak rates, initial production rates, current production rates, 30-day production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of PetroTal. The Company cautions that such results should be considered to be preliminary.

FOFI DISCLOSURE: This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about PetroTal's prospective results of operations and production results, 2024 drilling program and budget, well investment payback, cash position, liquidity and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this press release was approved by management as of the date of this press release and was included for the purpose of providing further information about PetroTal's anticipated future business operations. PetroTal and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. PetroTal disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this press release complies with the requirements of Canadian securities legislation, including NI 51-101. Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in PetroTal's guidance. The Company's actual results may differ materially from these estimates.

CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2024, and 2023

PetroTal

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MANAGEMENT'S REPORT

The accompanying audited Consolidated Financial Statements and all information in the Management's Discussion and Analysis, and notes to the Consolidated Financial Statements are the responsibility of management. The Consolidated Financial Statements were prepared by management in accordance with IFRS® Accounting Standards as issued by the International Accounting Standards Board ("IASB") outlined in the notes to the Consolidated Financial Statements. Other financial information appearing throughout the report is presented on a basis consistent with the Consolidated Financial Statements.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded, and financial records properly maintained to provide reliable information for the presentation of Consolidated Financial Statements.

The Audit Committee meets quarterly with management and the independent auditors to review auditing matters, financial reporting issues, and to satisfy itself that all parties are properly discharging their responsibilities. The Audit Committee also reviews the Consolidated Financial Statements, the management's discussion and analysis of financial results, and the independent auditor's report. The Audit Committee reports its findings to the Board of Directors for its approval of the Consolidated Financial Statements for issuance to the shareholders.

The Consolidated Financial Statements have been audited, on behalf of the shareholders, by the Company's independent auditors, in accordance with Canadian generally accepted auditing standards. Independent auditor has full and free access to the Audit Committee.

Signed "Manuel Pablo Zuniga-Pflucker"
Manuel Pablo Zuniga-Pflucker
President and Chief Executive Officer

Signed "Camilo McAllister"
Camilo McAllister
Executive VP and Chief Financial Officer

March 18, 2025

Deloitte.

Deloitte LLP
Suite 700 850-2nd Street SW
Calgary AB T2P 0R8
Canada

Tel: 403-267-1700
Fax: 403-264-2871

Independent Auditor’s Report

To the Shareholders of PetroTal Corp.

Opinion

We have audited the consolidated financial statements of PetroTal Corp. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2024 and 2023, and the consolidated statements of earnings and other comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2024 and 2023, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (“IASB”).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor’s Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2024. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Derivative Assets and Derivate Liabilities (embedded derivative) — Refer to Note 9 to the financial statements

Key Audit Matter Description

The company has an agreement for the sale of crude oil with Petroleos del Peru (PetroPeru S.A. a state owned company based in Peru). Under the agreement, the Company has exposure to the volatility of oil commodity prices until the crude oil is finally sold by PetroPeru to its customers at the Bayovar terminal (i.e., final settlement date). The exposure to fluctuations of future commodity prices is an embedded derivative and is measured at fair value at the end of the reporting period. The fair value of the derivative is calculated using the future strip prices of Brent on the estimated final settlement dates for each shipment that has not reached Bayovar terminal.

Determining the fair value of the embedded derivative required management to make significant estimates and assumptions regarding future strip prices of Brent on the estimated final settlement dates. Auditing these estimates and assumptions required a high degree of auditor judgment in applying audit procedures and in evaluating the results of those procedures. This resulted in an increased extent of audit effort.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to the fair value determination of the embedded derivative included the following, among others:

- Evaluated management's ability to accurately estimate the final settlement dates by:

  - Comparing historical sales settlement dates with management's estimated final settlement dates;
  - Obtaining corroborating evidence to support management's estimate of the settlement date, as well as assessing whether there was any evidence contradicting management's estimates;

- Evaluated the reasonableness of the prices used in the determination of the fair value of the embedded derivative by independently assessing the price to future third-party strip prices of Brent, considering the estimated final settlement dates; and

- Recalculated the fair value of the embedded derivative and compared it to the fair value determined by management.

Property, Plant and Equipment – Petroleum interests - Refer to Note 11 to the financial statements

Key Audit Matter Description

The Company's property, plant and equipment includes petroleum interests. Petroleum interests are measured by depleting the assets on a unit-of-production method ("depletion") based on total estimated proved plus probable reserves. The Company engages independent reserve engineers to estimate the proved plus probable reserves using estimates, assumptions, and engineering data. The development of the Company's reserves used to evaluate depletion requires management to make significant estimates and assumptions related to future crude oil prices, reserves, and future operating and development costs.

Given the significant judgments made by management related to future crude oil prices, reserves, and future operating and development costs, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgement in applying audit procedures, including the extent of reliance on management's expert, and in evaluating the results of those procedures. This resulted in an increased extent of audit effort.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to future crude oil prices, reserves, and future operating and development costs used to determine depletion included the following, among others:

- Evaluated future crude oil prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the future crude oil prices selected by management;

- Evaluated the Company's independent reserve engineers by examining reports and assessed their scope of work and findings; and assessing the competence, capability, and objectivity by evaluating their relevant professional qualifications and experience;

- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes;

- Evaluated the reasonableness of future operating and development costs by testing the source financial information underlying the estimate, comparing future operating and development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management’s Discussion and Analysis prior to the date of this auditor’s report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor’s report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Christopher Gill.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Alberta
March 18, 2025

CONSOLIDATED BALANCE SHEETS

($ thousands of US Dollars)

	Note	December 31 2024	December 31 2023
ASSETS			
Current Assets			
Cash	4	102,783	90,568
Restricted cash	4	5,745	14,731
VAT receivable	5	23,023	9,709
Trade and other receivables	6	65,832	58,602
Inventory	7	13,570	12,792
Prepaid expenses	8	13,901	7,462
Derivative assets	9	1,307	9,318
Total Current Assets		226,161	203,182
Non-current Assets			
Restricted cash	4	6,000	6,000
Trade receivable	6	19,279	20,370
Exploration and evaluation assets	10	10,406	8,973
Property, plant and equipment	11	537,018	399,564
Deferred income tax asset	23	1,963	13,045
Prepaid expenses	8	7,000	—
VAT receivable	5	2,329	2,226
Derivative assets	9	311	4,926
Total Non-current Assets		584,306	455,104
Total Assets		**810,467**	**658,286**
LIABILITIES AND EQUITY			
Current Liabilities			
Trade and other payables	13	94,955	79,328
Income tax payable	23	19,744	—
Lease liabilities	15	10,426	4,555
Short-term debt	12	10,047	—
Total Current Liabilities		135,172	83,883
Non-current Liabilities			
Long-term derivative liabilities	9	10,534	6,832
Lease liabilities	15	44,215	24,315
Decommissioning liabilities	14	34,383	22,147
Deferred income tax liabilities	23	72,548	55,109
Other long-term obligations		2,107	2,058
Total Non-current Liabilities		163,787	110,461
Total Liabilities		298,959	194,344
Equity			
Share capital	16	139,198	140,672
Contributed surplus		11,332	9,853
Retained earnings		360,978	313,417
Total Equity		511,508	463,942
Total Liabilities and Equity		**810,467**	**658,286**

See accompanying notes to the consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS AND OTHER COMPREHENSIVE INCOME

($ thousands of US Dollars, except per share amounts)
For the years ended December 31

	Note	2024	2023
REVENUES			
Oil revenues, net of royalties and social fund	17	333,993	286,263
Total revenue		333,993	286,263
EXPENSES			
Operating		44,320	32,446
Erosion expense	24	10,117	—
Direct transportation	20	15,348	14,963
General and administrative	18	36,291	28,049
Finance expense	19	3,156	15,341
Commodity price derivatives loss	9	10,424	12,479
Depletion, depreciation and amortization		62,242	39,801
Foreign exchange loss (gain)		743	(323)
Total expenses		182,641	142,756
Income before income taxes		**151,352**	**143,507**
Current income tax expense	23	11,381	7,236
Deferred income tax expense	23	28,521	25,766
Net income and comprehensive income		**111,450**	**110,505**
Basic earnings per share		0.12	0.12
Diluted earnings per share		0.12	0.12
Weighted average number of common shares outstanding (000's)			
Basic		914,716	900,075
Diluted		935,686	920,899

See accompanying notes to the consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

($ thousands of US Dollars, except per share amounts)
For the years ended December 31

	Note	2024	2023
Share capital			
Balance, beginning of year		140,672	130,196
Repurchase of shares	16	(1,474)	(1,839)
Exercise of warrants	16	—	12,315
Balance, end of period		139,198	140,672
Contributed surplus			
Balance, beginning of year		9,853	6,262
Share based compensation plan		1,479	3,591
Balance, end of period		11,332	9,853
Retained earnings			
Balance, beginning of year		313,417	262,873
Dividends paid	16	(60,472)	(55,566)
Net income and comprehensive income		111,450	110,505
Repurchase of shares	16	(3,416)	(4,395)
Balance, end of period		360,978	313,417
Total Equity		511,508	463,942

See accompanying notes to the consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

($ thousands of US Dollars, except per share amounts)
For the years ended December 31

	Note	2024	2023
Cash flows from operating activities			
Net income		111,450	110,505
Adjustments for:			
Depletion, depreciation and amortization		62,242	39,801
Accretion of decommissioning obligations	14	1,292	994
Share based compensation plan		1,528	4,340
Commodity price unrealized derivatives loss	9	6,683	10,223
Finance expenses		3,577	10,473
Deferred income tax expense	23	28,521	25,766
Changes in working capital:			
- Receivables and taxes		(13,522)	26,668
- Prepaid expenses		(9,043)	(746)
- Inventory		(302)	497
- Trade and other payables		10,253	9,445
- Commodity price realized derivatives	9	9,645	2,734
- Current income tax payable	23	18,586	—
Cash paid for income taxes		(150)	(1,241)
Net cash provided by operating activities		230,760	239,459
Cash flows from investing activities			
Property, plant and equipment additions	11	(161,393)	(106,822)
Exploration and evaluation asset additions	10	(1,434)	(1,631)
Asset acquisition	11	(1,700)	—
Non-cash changes in working capital		(1,788)	2,700
Net cash used in investing activities		(166,315)	(105,753)
Cash flows from financing activities			
Interest and fees paid		(34)	(8,426)
Net proceeds from exercise of warrants	16	—	12,315
Repayment of debt principal		—	(100,000)
Funds received from credit facility	12	10,000	20,000
Payments of dividends to shareholders		(60,472)	(55,566)
Repurchase of shares		(4,891)	(6,234)
Payment of current lease liabilities	15	(5,819)	(4,465)
Net cash used in financing activities		(61,216)	(142,376)
Increase (decrease) in cash		3,229	(8,670)
Cash, beginning of period		90,568	104,340
Restricted cash	4	8,986	(5,102)
Cash, end of the period		**102,783**	**90,568**

See accompanying notes to the consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2024 and 2023.
All amounts are stated in thousands of United States Dollars ($) unless otherwise indicated.

1. CORPORATE INFORMATION

PetroTal Corp. (the "Company" or "PetroTal") is a publicly-traded energy company incorporated and domiciled in Canada. The Company is engaged in the exploration, appraisal and development of oil and natural gas in Peru, South America. The Company's registered office is located at 4200 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada.

These Consolidated Financial Statements (the "Financial Statements") have been prepared on a going concern basis, which assumes that the Company will continue its operations for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of business.

The Company evaluated subsequent events and transactions that occurred after the balance sheet date up to the date that the Financial Statements were issued.

These Financial Statements were approved for issuance by the Company's Board of Directors on March 18, 2025, on the recommendation of the Audit Committee.

2. BASIS OF PREPARATION

STATEMENT OF COMPLIANCE

The Company prepares its annual Financial Statements in accordance with International Financial Reporting Standards ("IFRS®" or "IFRS® Accounting Standards") as issued by the International Accounting Standards Board ("IASB").

BASIS OF MEASUREMENT

These Financial Statements have been prepared on a historical cost basis except for certain financial instruments that have been measured at fair value. In addition, these Financial Statements have been prepared using the accrual basis of accounting.

PRINCIPLES OF CONSOLIDATION

The Company's Financial Statements include the accounts of the Company and its subsidiaries. The Financial Statements of the subsidiaries are prepared for the same reporting period as the parent Company's, using consistent accounting practices.

Inter-company balances and transactions, and any unrealized gains arising from inter-company transactions with the Company's subsidiaries, are eliminated on consolidation.

The entities included in the Company's Financial Statements are PetroTal Corp. and its 100% owned subsidiaries PetroTal USA Corp., PetroTal LLC, PetroTal Energy International (Peru) Holdings B.V., PetroTal Peru

B.V., Petrolifera Petroleum Del Peru S.R.L., PetroTal Peru S.R.L., and Ucawa Energy S.A.C. (formerly CEPSA Peruana S.A.C.).

USES OF ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGEMENTS

The preparation of the Company's Financial Statements requires management to make judgement, estimates, and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and other factors that are considered relevant. Actual results may differ from estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the same period if the revision affects only that period or in the period of the revision and future periods if the revision affects current and future periods.

Estimates and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are summarized below:

Functional Currency

The functional currency of each of the Company's entities is the United States dollar, which is the currency of the primary economic environment in which the entities operate.

Decommissioning Obligations

Decommissioning obligations will be incurred by the Company at the end of the operating life of wells or supporting infrastructure. The ultimate asset decommissioning costs and timing are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques, and experience at other production sites. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The expected amount of expenditure is estimated using a discounted cash flow calculation with a risk-free discount rate. Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed, and the associated costs can be estimated.

Deferred Tax Assets & Liabilities

The estimation of income taxes includes evaluating the recoverability of deferred tax assets based on an assessment of the Company's ability to utilize the underlying future tax deductions against future taxable income prior to the expiration of those deductions. Management assesses whether it is probable that some or all of the deferred income tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income, which in turn is dependent upon the successful discovery, extraction, development and commercialization of oil and gas reserves. To the extent that management's assessment of the Company's ability to utilize future tax deductions changes, the Company would be required to recognize more or fewer deferred tax assets, and future income tax provisions or recoveries could be affected. The measurement of deferred income tax provision is subject to uncertainty associated with the timing of future events and changes in legislation, tax rates and interpretations by tax authorities.

Provisions, Commitments and Contingent Liabilities

Amounts recorded as provisions and amounts disclosed as commitments and contingent liabilities are estimated based on the terms of the related contracts and management's best knowledge at the time of issuing the Financial Statements. The actual results ultimately may differ from those estimates as future confirming events occur.

MATERIAL ACCOUNTING POLICIES

a. Cash and Restricted Cash

Cash includes deposits held with banks in Canada, the United States and Peru that are available on demand and highly liquid. The Company's restricted cash is cash reserved for letters of credit guaranteeing the Company's commitments for the exploration of Block 107, acquisition of qualified hydrocarbon assets, permitted hedging programs, and the 2.5% social development trust fund ("social fund") for the benefit of local communities. The restricted cash is not available for the Company's immediate or general business use.

b. Property, Plant and Equipment

Property, plant and equipment ("PP&E") is recorded at cost less accumulated depreciation. Depreciation begins when the asset is put into service and is calculated annually using the straight-line method. The cost of maintenance and repairs is charged to expense as incurred. The cost of significant renewals and improvements is added to the carrying amount of the respective asset. When assets are retired, or otherwise disposed of, the cost and related accumulated depreciation are removed from the balance, and any resulting gain or loss is reflected in the consolidated statements of earnings and comprehensive income.

When commercial production in an area has commenced, petroleum properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable reserve life. Proved plus probable reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of future crude oil prices, reserves and future operating and development costs that affect unit-of-production calculations are accounted for on a prospective basis.

c. Leases

The Company assesses each new contract to determine whether it contains a lease. A specific asset is the subject of a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The Company allocates contract consideration to the lease and non-lease components on the basis of their relative stand-alone prices.

The right-of-use asset is initially measured at cost, which includes: (i) the amount of the initial measurement of the lease liability, (ii) any lease payments made at or before the lease commencement date, less any lease incentives received, (iii) any initial direct costs incurred, and (iv) an estimate of restoration costs.

The lease liability and initial right-of-use asset are recognized at the lease commencement date measured at the present value of fixed lease payments (including in-substance fixed payments) plus the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, discounted at a rate the Company would be required to borrow over a similar term.

Key judgements include whether a contract identifies an asset (or a portion of an asset), whether the lessee obtains substantially all of the economic benefits of the asset over the contract term, whether the lessee has the right to direct the asset's use, which components are fixed or variable in nature and the discount rate. The Company applied its incremental borrowing rate for leases where the implicit rate cannot be readily determined. Right-of-use assets are presented within property, plant and equipment.

After initial recognition, the lease liability is accreted for the passage of time and reduced for lease settlements made during each period. If the lease terms indicate that the Company will exercise a purchase option, the right-of-use asset is depreciated from the lease commencement date to the end of the useful life of the underlying asset. Otherwise, the right-of-use asset is depreciated to the earlier of the end of the useful life of the underlying asset or to the end of the lease term. Additionally, the Company remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

(a) The lease term has changed or there is a significant event or change in circumstances resulting in a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

(b) The lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using an unchanged discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used).

(c) A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

d. Impairment

Financial assets carried at amortized cost

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net earnings (loss). Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

Non-financial assets

At each reporting date, the carrying amounts of the Company's non-financial assets are reviewed to determine whether there is indication of impairment, except for E&E assets, which are reviewed when circumstances indicate impairment may exist. If there is indication of impairment, the asset's recoverable amount is estimated and compared to its carrying value. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit). The recoverable amount of an asset or a CGU is the greater of its value in use or its fair value less costs to sell. The Company's CGUs are not larger than a segment. In assessing both fair value less costs to sell and value in use, the estimated future cash flows are discounted to their present value using an after-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. An impairment loss is recognized if the carrying amount of an asset or its CGU (Company has a single segment) exceeds its estimated recoverable amount. Impairment losses are recognized in net earnings (loss). Fair value less costs to sell and value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

E&E assets are tested for impairment when they are transferred to petroleum properties and also if facts and circumstances suggest that the carrying amount of E&E assets may exceed the recoverable amount. Impairment indicators are evaluated at a CGU level. Indication of impairment includes:

- Expiry or impending expiry of lease with no expectation of renewal;
- Lack of budget or plans for substantive expenditures on further E&E;
- Cessation of E&E activities due to a lack of commercially viable discoveries; and
- Carrying amounts of E&E assets are unlikely to be recovered in full from a successful development project.

Impairment losses recognized in prior years are assessed at each reporting date for indication that the loss has decreased or no longer exists. An impairment loss may be reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

e. Inventory

Inventory consists of crude oil and supplies to be used in the production and exploration activities, and is measured at the lesser of cost and net realizable value. The cost of crude oil inventory includes all costs incurred in bringing the inventory to its storage location. These costs, including operating expenses, royalties, transportation and depletion, are capitalized in the ending inventory balance. The cost of the inventory is recognized using the weighted average method.

f. Financial Instruments

On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the classification of the financial instrument:

- Fair value through profit or loss - subsequently carried at fair value with changes recognized in net earnings (loss). Financial instruments under this classification include cash and cash equivalents, and derivative commodity contracts;
- Fair value through other comprehensive income - transaction costs under this classification are expensed as incurred. Financial instruments under this classification include derivative assets and liabilities where hedge accounting is applied; and
- Amortized cost - subsequently carried at amortized cost using the effective interest rate method. Financial instruments under this classification includes accounts receivable, accounts payable and accrued liabilities, and short- and long-term debt.

IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Derivative instruments are not used for trading or speculative purposes. The Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting. As a result, the Company's policy is to classify all financial derivative contracts at fair value through profit or loss and to record them on the Consolidated Balance Sheet at fair value with a corresponding gain or loss in net earnings (loss). Attributable transaction costs are recognized in net earnings (loss) when incurred. The estimated fair value of all derivative instruments is based on quoted market prices and/or third-party market indications and forecasts.

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not closely related to those of the host contract; when the terms of the embedded derivatives are the same as those of a freestanding derivative; and when the combined contract is not measured at fair value through profit or loss. The timing of the expected delivery to the final point of sale drives the value of the embedded derivative in the Petroperu contract, as the fair value of the derivative depends on the oil price at the time of the expected sale date at the final point of sale. Refer to Note 9 for the classification and measurement of these financial instruments.

The Company's financial instruments consist of cash, trade and other receivables, derivative assets, trade and other payables, derivative liabilities, and short and long-term debt and are included in the Company's balance sheet. The Company initially measures financial instruments at fair value.

g. Exploration and Evaluation Assets

E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. These costs include acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to property, plant and equipment, where they are depleted. Exploration and evaluation assets are not amortized during the exploration and evaluation stage. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income (loss) as impairment of exploration and evaluation assets.

h. Decommissioning Obligations

The Company recognizes a decommissioning liability in relation to the evaluation and exploration assets and to property, plant and equipment, in the period in which a reasonable estimate of the fair value can be made of the statutory, contractual, constructive or legal liabilities associated with the retirement of the oil and gas properties, facilities and pipelines. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a discount rate. The estimates are reviewed periodically. Changes in the provision resulting from changes to the timing of expenditures, climate-related matters, costs or risk-free rates are dealt with prospectively by recording an adjustment to the provision and a corresponding adjustment to property, plant and equipment or exploration and evaluation assets. The unwinding of the discount on the decommissioning provision is charged to the consolidated statements of earnings and comprehensive income. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and the remaining balance of the actual costs is recorded in the consolidated income statement.

i. Erosion Costs

Erosion control costs are expenses incurred by the Company to protect the producing fields and nearby community from erosion cause by the river. These costs will be capitalized and/or expensed depending on the nature of the outflow and the direct benefits received by the Company or the community. Erosion costs are presented in a separate expense line in the Statement of Earnings and Other Comprehensive Income, recognized as incurred and for a better reliable measurement. The financial statement notes presents the nature, measurement basis, and transparency of this new activity.

j. Income Taxes

Income tax expense is comprised of current and deferred tax. Current tax and deferred tax are recognized in net income or loss except to the extent that it relates to a business combination or items recognized directly in equity or in other comprehensive income or loss. Current income taxes are recognized for the estimated income taxes payable or receivable on taxable income or loss for the current year and any adjustment to income taxes payable in respect of previous years. Current income taxes are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date. Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base, except for taxable temporary differences arising on the initial recognition of goodwill and temporary differences arising on the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting nor taxable profit or loss. Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized. At the end of each reporting period the Company reassesses unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

k. Revenue Recognition

Under IFRS 15, revenue is recognized when a customer obtains control of the goods or services as stipulated in a performance obligation. Determining whether the timing of the transfer of control is at a point in time or over time requires judgement and can significantly affect when revenue is recognized. In addition, the entity must also determine the transaction price and apply it correctly to the goods or services contained in the performance obligation.

The Company's revenue is derived exclusively from contracts with customers. Revenue associated with the sale of crude oil and gas is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil and gas usually coincides with title passing to the customer and the customer taking physical possession. Company mainly satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Revenues from the sale of crude oil and gas are recognized by reference to actual volumes delivered at contracted delivery points and prices. Prices are determined by reference to quoted market prices in active markets, adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are recognized prior to the deduction of transportation costs. Revenues are measured at the fair value of the consideration received.

l. Foreign Currency Translation

Transactions in foreign currencies are initially translated into the functional currency using the exchange rate on the transaction date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the consolidated statements of earnings and comprehensive income. Each subsidiary in the group is measured using the currency of the primary economic environment in which the entity operates, which is its functional currency.

m. Earnings per Share

The Company presents basic and diluted earnings per share (“EPS”) data for its common shares (the “Common Shares”). Basic EPS is calculated by dividing the net profit or loss attributable to common shareholders of the Company by the weighted average number of Common Shares outstanding during the period. Diluted EPS is determined by dividing the net profit or loss attributable to common shareholders by the weighted average number of Common Shares outstanding during the year, plus the weighted average number of Common Shares that would be issued on conversion of all dilutive potential Common Shares into Common Shares. Those potential Common Shares comprise share options granted.

n. Fair Value Measurements

Financial instruments recorded at fair value in the consolidated balance sheet (or for which fair value is disclosed in the notes to the Financial Statements) are categorized based on the fair value hierarchy of inputs. The three levels in the hierarchy are described below:

Level I

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 volume to provide continuous pricing information.

Level II

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

Level III
Valuations are made using inputs for the asset or liability that are not based on observable market data. The Company uses Level III inputs for fair value measurements in inputs such as commodity prices in impairment assessments.

o. Business Combinations

The Company adopted the amendments to IFRS 3 – Business Combinations. Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the acquired assets constitute a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination are measured at their fair values. If applicable, the excess or deficiency of the fair value of net assets acquired compared to consideration paid is recognized as a gain on business combination or as goodwill on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period incurred. As part of the assessment to determine if the acquisition constitutes a business, the Company may elect to apply the concentration test on a transaction by transaction basis. The test is met if substantially all of the fair value related to the gross assets acquired is concentrated in a single identifiable asset (or group of similar assets) resulting in the acquisition not being deemed a business and recorded as an asset acquisition. The amendments introduced an optional concentration test, narrowed the definitions of a business and outputs, and clarified that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs.

Prior Year Reclassification

In the preparation of the Financial Statements, we identified as of December 31, 2023 a misclassification of $2.3 million between the lease payments due in the short and long-term. As a result, we revised the balances as of December 31, 2023, to properly reflect the classification of lease payments with no impact to the total lease liability balance.

3. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

ACCOUNTING STANDARDS ISSUED

New accounting standards and interpretations were issued and are mandatory for accounting periods starting on or after January 1, 2024. The new accounting standards and interpretations, which did not have a significant impact on the Company's Financial Statements upon adoption, are as follows:

- Amendments to IAS 1 - Classification of Liabilities as Current or Non-current - In January 2020 and October 2022, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classifying liabilities as current or non-current. An additional requirement has been introduced to require disclosure when a liability arising from a loan agreement is classified as non-current and the entity's right to defer settlement is contingent on compliance with future covenants within twelve months. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, and must be applied retrospectively.

- Amendments to IFRS 16 - Lease Liability in a Sale and Leaseback - In September 2022, the IASB issued amendments to Leases ("IFRS 16") to specify the requirements that a seller-lessee uses in measuring the lease liability arising in a sale and leaseback transaction, to ensure the seller-lessee does not recognize any amount of the gain or loss that relates to the right of use it retains. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, and must applied retrospectively to sale and leaseback transactions entered into after the date of initial application of IFRS 16.

- Amendments to IAS 7 and IFRS 7 - Supplier Finance Arrangements - In May 2023, the IASB issued amendments to IAS 7 Statement of Cash Flows and IFRS 7 Financial Instruments: Disclosures to clarify the characteristics of supplier finance arrangements and require additional disclosure of such arrangements. The disclosure requirements in the amendments are intended to assist users of financial statements in understanding the effects of supplier finance arrangements on an entity's liabilities, cash flows and exposure to liquidity risk. The amendments are effective for annual reporting periods beginning on or after January 1, 2024.

NEW ACCOUNTING STANDARD ISSUED BUT NOT EFFECTIVE

New accounting standards and interpretations were issued and are mandatory for future accounting periods. With respect to IFRS 18 (Presentation and Disclosure in Financial Statements) issued by the IASB in April 2024, the Company is currently evaluating the impact on the Company's Financial Statements. Retrospective application of the standard is mandatory for annual reporting periods starting from January 1, 2027 onwards with earlier application permitted.

4. CASH AND RESTRICTED CASH

The following table sets out cash and restricted cash balances held in different currencies:

	December 31 2024	December 31 2023
Balances held in:		
US dollars	109,586	100,996
Peruvian soles	925	3,296
English pounds	1,248	3,270
Canadian dollars	2,769	3,737
Total	114,528	111,299
Represented as:		
Cash	102,783	90,568
Restricted cash current	5,745	14,731
Restricted cash non-current	6,000	6,000

Current restricted cash of $5.7 million, is primarily related to the social fund and letters of credit bank guarantees for Block 107 exploration wells. The $6.0 million of non-current restricted cash is related to the permitted hedging programs (see Note 9).

In March 2023, Peru's President signed the Supreme Decree authorizing Perupetro S.A. to execute the amendment incorporating the 2.5% social trust fund (value of the monthly oil produced in Bretana's Block 95, less transportation, for the benefit of local communities) into the Block 95 license contract, effective and retroactive to January 1, 2022. For the years ended December 31, 2024 and 2023, the Company paid to the community $17.8 million and $0.2 million, respectively.

5. VAT RECEIVABLE

	December 31 2024	December 31 2023
VAT receivable current	23,023	9,709
VAT receivable non-current	2,329	2,226
Total VAT receivables	25,352	11,935

Valued Added Tax ("VAT") in Peru is levied on the purchase of goods and services and is recoverable on sales of goods and services. The Company increased $39.1 million and recovered $25.9 million of VAT during the year ended December 31, 2024, and expects to recover $23.0 million of VAT in the short-term.

6. TRADE AND OTHER RECEIVABLES SHORT AND LONG TERM

	December 31 2024	December 31 2023
Trade receivables	84,754	76,163
Other receivables	357	2,809
Total trade and other receivables	85,111	78,972
Represented as:		
Current receivables	65,832	58,602
Non-current receivables	19,279	20,370

At December 31, 2024, trade receivables represent revenue related to the sale of oil. The trade balance is mostly comprised of $22.0 million due from Petroperu ($2.7 million is short term and $19.3 million is long term), $58.7 million from export sales through Brazil and $4.0 million from Ucawa Energy S.A.C. customers (all of which is due short term). No credit losses on the Company's trade receivables have been incurred and all short-term receivables are current.

7. INVENTORY

	December 31 2024	December 31 2023
Oil inventory	2,676	813
Materials, parts and supplies	10,894	11,979
Total inventory	13,570	12,792

Oil inventory consists of the Company's oil barrels, which are valued at the lower of cost or net realizable value. Costs include operating expenses, royalties, transportation, and depletion associated with production. Costs capitalized as inventory will be expensed when the inventory is sold. At December 31, 2024, the oil inventory balance of $2.7 million consists of 85,863 barrels of oil (including 3,466 barrels from Ucawa Energy S.A.C.) valued at $31.16/bbl. (December 31, 2023: $0.8 million, based on 35,320 barrels at $23.01/bbl.). Materials, parts and supplies, including diluent, are expected to be consumed in the short-term.

8. PREPAID EXPENSES

	December 31 2024	December 31 2023
Erosion control project advances	3,296	—
Advances to contractors	7,450	507
Prepaid expenses and others	10,155	6,955
Total advances and prepaid expenses	20,901	7,462
Represented as:		
Current prepaid expenses	13,901	7,462
Non-current prepaid expenses	7,000	—

At December 31, 2024, prepaid expenses and others were comprised of $5.9 million in Peruvian income tax prepaid and $4.2 million in insurance, prepaid services for consultants, and other related services. Advances to contractors include $7.0 million related to power plant projects in long-term.

9. RISK MANAGEMENT

	December 31, 2024		December 31, 2023	
	Carrying	Fair Value	Carrying	Fair Value
Cash and restricted cash	114,528	114,528	111,299	111,299
Trade and other receivables	65,832	65,832	58,602	58,602
Short-term derivative assets	1,307	1,307	9,318	9,318
Trade receivable long-term	19,279	19,279	20,370	20,370
Long-term derivative assets	311	311	4,926	4,926
Short and long-term debt	10,047	10,047	—	—
Trade and other payables	94,955	94,955	79,328	79,328
Long-term derivative liabilities	10,534	10,534	6,832	6,832

The table above details the Company's carrying value and fair value of financial instruments including cash and restricted cash, trade and other receivables, derivatives, debt and trade and other payables, all of which are classified as financial assets and liabilities and reported at amortized cost or fair value. The Company is exposed to various financial risks arising from normal-course business exposure. These risks include market risks relating to foreign exchange rate fluctuations and commodity price risk as well as liquidity.

COMMODITY PRICE DERIVATIVES

The derivative asset is classified as a Level 2 fair value measurement. The Petroperu Saramuro agreement, signed with Petroperu during 2021, includes a clause for the purchase price adjustment. The initial sales price is based on the arithmetic average of the ICE Brent Crude 8 month forward price. The realized price is based on the tender price of the oil that is sold at the Bayovar terminal. The purchase price adjustment is the realized price less the initial sales price. If the purchase price adjustment is negative, the Company will compensate Petroperu for the amount, multiplied by the volume sold or arranged by Petroperu. If the purchase price adjustment is positive, the Company will be compensated by Petroperu.

The fair value of the embedded derivative, considering an average future Brent price marker differential, was recorded as a gain (loss) on commodity price derivatives at December 31, 2024 and 2023.

	December 31 2024	December 31 2023
Net derivative asset at beginning of period	7,412	20,370
Cash settlements	(5,904)	(478)
Realized loss	(3,741)	(2,256)
Unrealized loss	(6,683)	(10,224)
Net derivative (liability) asset at end of period	(8,916)	7,412
Represented as:		
Short-term derivative assets	1,307	9,318
Long-term derivative assets	311	4,926
Long-term derivative liabilities	(10,534)	(6,832)

Sales delivery / Executed month	Expected settlement month	Volume (bbls. in thousands	Price range $/bbl.	Hedged range $/bbl.	Net Derivative Asset
Peru Embedded Derivatives [1]					
Apr-21 to Feb-22	Sep-26 to Nov-28	1,882	62.49 to 85.26	67.95 to 69.44	(10,223)
Corporate Derivatives Hedging [2]					
Aug-24 and Oct-24	Jan-25 to Oct-25	1,655	—	65.00 to 104.50	1,307
				Net Derivative (Liability)	**(8,916)**

1) Embedded derivative related to original Petroperu sales agreement.

   For the year ended December 31, 2024, the Company realized true-up derivative gains from final sales at Bayovar of 540,132 bbls. (during the year) for $5.9 million. At December 31, 2024, 1.9 million barrels (2.4 million at December 31, 2023) remain in the pipeline or storage tanks, awaiting final sale by Petroperu. During the year, a decrease in future oil prices to the Peru embedded derivative resulted in a net derivative liability. A 1% change to the hedged range price would result in a $1.2 million change to the net derivative liability. The derivative gains/losses are only materialized when oil is effectively sold to third parties at Bayovar.

2) Corporate hedge program to cover a portion of 2024 and 2025 production.

   During the year, the Company executed hedging agreements that consisted of multiple trades that totaled 2.6 million bbls. of Brent oil with settlements dates from September 2024 to October 2025. The hedge types included put options of $65.00 per bbl., call options of $84.20 and $84.25 per bbl., and call options of $104.25 and $104.50 per bbl. At December 2024, there was a remainder of 1.7 million in hedged barrels of Brent oil that resulted in a net derivative asset of $1.3 million.

FOREIGN EXCHANGE RATE RISK

The Company's functional currency is the United States dollar. Foreign exchange gains or losses can occur on translation of working capital denominated in currencies other than the functional currency of the jurisdiction which holds the working capital item. Excluding the impact of changes in the cross-rates, a 1% fluctuation in translation rates would have nil impact on net income or loss, based on foreign currency balances held at December 31, 2024.

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's liquidity risk is impacted by current and future commodity prices. If required, the Company will also consider additional short-term financing or issuing equity in order to meet its future liabilities. Declines in future commodity prices could affect the Company's ability to fund ongoing operations. The current economic environment may have significant adverse impacts on the Company including, but not exclusively:

- material declines in revenue and cash flows as a result of the decline in commodity prices;
- declines in revenue and operating activities due to reduced capital programs and constrained oil production;
- inability to access financing sources;
- increased risk of non-performance by the Company's customers and suppliers;
- interruptions in operations as the Company adjusts personnel to the dynamic environment; and,
- delivery and transportation of oil at Bayovar port and sale swap price risk.

Estimates and judgements made by management in the preparation of the Financial Statements are subject to a certain degree of measurement uncertainty during this volatile period.

CREDIT RISK

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss to the Company. The Company's VAT is primarily for sales tax credits on exploration and drilling expenses incurred during the year and in prior years. These credits will be applied to future oil development activities or recovered as per the sales tax recovery legislation currently in effect. The Company's trade receivable balance relates mostly to oil sales and purchase price adjustments to two customers, being Petroperu, a state-owned company and Novum, an oil trading company. The Company has a long-term sales agreement for oil exports through Brazil, whereby sales are FOB Bretana. Sales through the ONP pipeline are due and payable 240 days after the final delivery of the oil to the Bayovar terminal. For the year ended December 31, 2024, 89% of oil sales were to Novum (Brazil export route) and 11% were to Petroperu (Iquitos refinery). The Company has not experienced any material credit losses in the collection of its trade receivables. The Company periodically assesses the recoverability of all trade receivables through discussions with its customers, review of credit rating agency reports or review of other third-party information.

Impairment to a financial asset is only recorded when there is objective evidence of impairment and the loss event has an impact on future cash flow and can be reliably estimated. Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. Management believes that there is no risk on the recoverability and or applicability of the sales tax credits. Therefore, no impairment to the carrying value of these assets has been estimated. The Company has deposited its cash, cash equivalents and restricted cash with reputable financial institutions, with which management believes the risk of loss to be remote. The maximum credit exposure associated with financial assets is their carrying value. At December 31, 2024, the cash, cash equivalents and restricted cash were held with six different institutions from three countries, mitigating the credit risk of a collapse of one particular bank.

10. EXPLORATION AND EVALUATION ASSETS

The following table sets out a continuity of Exploration and Evaluation Assets:

Balance at January 1, 2023	7,342
Additions	1,631
Balance at December 31, 2023	8,973
Additions	1,434
Balance at December 31, 2024	10,406

The Company determined there were no impairment indicators of the exploration and evaluation assets balance at December 31, 2024 and December 31, 2023.

11. PROPERTY, PLANT AND EQUIPMENT

	Petroleum Interests	Right of Use Asset (Power Plant)	Other Assets	Total
Balance at January 1, 2023	288,279	20,712	2,919	311,910
Additions	105,151	—	1,671	106,822
Revisions to decommissioning obligations	7,760	—	—	7,760
Revisions to right of use asset	—	12,389	—	12,389
Depletion, depreciation and amortization	(36,964)	(1,328)	(1,025)	(39,317)
Balance at December 31, 2023	364,226	31,773	3,565	399,564
Additions	161,393	14,999	13,126	189,518
Additions and revisions to decommissioning obligations	181	—	—	181
Asset acquisition	9,078	—	—	9,078
Revisions to right of use asset	—	—	1,045	1,045
Depletion, depreciation and amortization	(59,124)	(2,470)	(774)	(62,368)
Balance at December 31, 2024	475,754	44,302	16,962	537,018

At December 31, 2024, $0.4 million of the depreciation, depletion and amortization expense was recorded as inventory (December 31, 2023: $0.3 million). The Company determined there were no impairment indicators of the property, plant and equipment balance at December 31, 2024 and December 31, 2023.

Asset Acquisition

On November 29, 2024, the Company closed the acquisition of CEPSA Peruana S.A.C., who owns a 100% working interest in Peru's Block 131, for a total cash consideration of $6.7M. The acquisition resulted in an increase of assets of approximately $22.2 million and liabilities of $15.5 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets based on the relative fair value at the date of acquisition. The assets acquisition costs of $0.3 million were capitalized. The amounts recognized on the date of acquisition to identifiable net assets were as follows:

	November 29, 2024
Net Assets acquired	
Cash & Cash equivalents	4,988
Trade receivables and other assets	5,179
Property, plant and equipment, net	12,036
Trade and other payables	(1,926)
Decommissioning liabilities	(13,589)
Total Net Asset acquired	**6,688**
Purchase consideration	6,688
Total Purchase consideration	**6,688**

12. SHORT AND LONG-TERM DEBT

At December 31, 2024 the Company had short term debt of $10.0 million at an interest rate of 5.99% to be paid in full 120 days from the date of borrowing. The proceeds will be used to fund short term working capital needs. The Company has $67.0 million in remaining available credit. No debt covenants were set forth by the lenders in the loan agreements and all lines of credit are available for one year with the option to renew.

Bank	Agreement Date	Balance	Line of Credit	Interest Rate	Payment Term	Collateral
BCP	March 2023	$10,047	$20,000	5.99 %	120 days	—
BanBif	April 2024	—	$2,000	—	90 days	—
Scotia Bank[(1)]	April 2024	—	$5,000	—	360 days	$5,000
JP Morgan Bank	May 2024	—	$20,000	—	120 days	—
GNB	August 2024	—	$10,000	—	180 days	—
Banco Pichincha	September 2024	—	$20,000	—	120 days	Insurance endorsement
Balance at December 31, 2024		$10,047	$77,000			

[1] The Scotia Bank $5.0 million cash collateral requirement was removed on January 23, 2025.

13. TRADE AND OTHER PAYABLES

	December 31 2024	December 31 2023
Trade payables	39,201	25,037
Accrued payables and other obligations	55,754	54,291
Total trade and other payables	94,955	79,328

At December 31, 2024 and December 31, 2023, trade payables and other payables are primarily related to the drilling and completion of wells and construction of production processing facilities. The other obligations are mainly related to the 2.5% social fund for the benefit of local communities, which totaled to $5.0 million at December 31, 2024 ($12.2 million at December 31, 2023).

14. DECOMMISSIONING LIABILITIES

Balance at January 1, 2023	13,393
Additions	5,390
Acquisition	—
Revisions to decommissioning liabilities	2,370
Expenditures	—
Accretion	994
Balance at December 31, 2023	22,147
Additions	3,205
Asset acquisition	13,590
Revisions to decommissioning liabilities	(5,851)
Expenditures	—
Accretion	1,292
Balance at December 31, 2024	34,383

The undiscounted uninflated value of estimated decommissioning liabilities is $64.4 million ($39.0 million in 2023). The present value of the liabilities was calculated using average risk-free rates between 4.8% to 6.3% (December 31, 2023: 5.3%) to reflect the market assessment of the time value of money as well as risks specific to the liabilities that have not been included in the cash flow estimates. The inflation rate used in determining the cash flow estimate was 2.0%. The revisions to the decommissioning liabilities includes changes to cost estimates, the risk free rates and adjustments for inflation.

In Q4, PetroTal acquired $13.6 million in decommissioning liabilities as part of the Ucawa Energy S.A.C. asset acquisition.

15. CURRENT AND NON-CURRENT LEASE LIABILITIES

In prior years, PetroTal commenced a service lease arrangement with a supplier that provides turnkey power generation equipment services. In Q4 2024, the Company signed an addendum to lease additional equipment, which resulted in a $15.0 million present value increase to the right of use assets and liabilities on the balance sheet. The Company has the option to buy the equipment on June 27, 2031 for $3.0 million. The incremental borrowing rate used to measure the lease liabilities was 8.5%. The lease term ends September 2031.

Also in Q4 2024, PetroTal executed an agreement to acquire a drilling rig from a Houston-based equipment company. The purchase of the rig was financed through a lease agreement (36 month term) with a Peruvian bank which resulted in a $13.3 million present value increase to the right of use assets and liabilities on the balance sheet. The Company has the option to buy the rig on October 31, 2028 for $0.1 million. The incremental borrowing rate used to measure the lease liability was 8.5%. The lease term ends December 2027.

The lease liabilities includes three office leases, one in Houston, Texas and two in Lima, Peru. The Houston lease was renewed with a 1.1 million present value increase for a term of 6.0 years with an incremental borrowing rate of 9.5%. The Lima leases are for 3-5 years with an incremental borrowing rate of 8.5% with no changes in present value.

Lease liabilities at January 1, 2023	19,642
Additions	—
Revisions	12,389
Payments	(4,465)
Interest on leases	1,304
Lease liabilities at December 31, 2023	28,870
Additions	28,125
Acquisition	15
Revisions	1,045
Payments	(5,819)
Interest on leases	2,405
Lease liabilities at December 31, 2024	54,641
Represented as:	
Current liability	10,426
Non-current liability	44,215

At December 31, 2024, total lease liabilities have the following minimum undiscounted annual payments:

Year	
2025	13,119
2026	13,155
Thereafter	40,973
Total	67,247

16. SHARE CAPITAL

Authorized share capital consists of an unlimited number of common shares without nominal or par value. The holders of common shares are entitled to one vote per share and are entitled to receive dividends as recommended by the Board of Directors.

	Thousands of Common Shares	Share Capital
Balance at January 1, 2023	862,209	130,196
Vesting of performance share units	1,557	—
Repurchase of shares	(11,327)	(1,839)
Warrants exercised	59,875	12,315
Balance at December 31, 2023	912,314	140,672
Vesting of performance share units	8,283	—
Repurchase of shares	(8,814)	(1,474)
Balance at December 31, 2024	911,783	139,198

DIVIDENDS

During the years ended December 31, 2024 and 2023, the Company paid dividends to shareholders in the amount of $60.5 million and $55.6 million, respectively. The Company paid dividends in the amount of $0.02 in Q1 2024, and $0.015 in each of the following quarters through Q4 2024. The Company's sustainable dividend policy is to pay dividends based on current liquidity exceeding $60 million.

NORMAL COURSE ISSUER BID

On May 22,2024, the Company renewed the NCIB which would end no later than May 23, 2025. This renewal includes the intention to purchase up to 14,600,000 common shares (representing approximately 2% of its outstanding common shares at May 10, 2024). Common shares purchased under the NCIB are cancelled.

During the years ended December 31, 2024 and 2023, the Company purchased 8,814,260 and 11,326,806 common shares under the NCIB for total consideration of $4.9 million and $6.5 million, respectively. The surplus between the total consideration and the carrying value of the shares repurchased was recorded against retained earnings.

SHARE BASED COMPENSATION

The Company has granted performance share units ("PSUs") to employees and deferred share units ("DSUs") to directors. The grant date fair value of PSUs granted to employees is recognized as share based compensation expense with a corresponding increase in contributed surplus over the vesting period. The Company granted PSUs to employees in accordance with the provisions of the Company's PSU plan. The PSUs either vest after three years or equally over three years and each PSU will entitle the holder to acquire between zero and two common shares of the Company, subject to the achievement of performance conditions relating to the Company's total shareholder return, net asset value and certain production, environmental, safety and operational milestones. The fair value of the PSUs is determined through a combination of Black-Scholes and probability weighted models. The following table details the terms of the PSUs outstanding at December 31, 2024:

	2024 Plan Share Units	2023 Plan Share Units
Vest date 3 years from grant date, exchangeable for up to 2 shares	3,526,270	3,685,322
Vests equally over 3 years from grant date, exchangeable for up to 2 shares	699,408	347,000
Vests equally over 3 years from grant date, exchangeable for up to 1-1.5 shares	2,025,939	1,132,997
Total units	6,251,617	5,165,319

The following assumptions were used for the Black-Scholes valuation of the PSUs granted:

	2024 Plan	2023 Plan
Risk-free interest rate	4.5%	3.8%
Expected Life	1-3 years	1-3 years
Annualized volatility	50%	50%

For the year ended December 31, 2024, the Company recognized $3.2 million of share based compensation expense in general and administrative expense, capital expenditures and operating expense (December 31, 2023: $4.4 million).

The Company issued DSUs to directors of the Company, pursuant to the Company's DSU plan and has 5,071,435 DSUs outstanding at December 31, 2024. The DSUs are fully vested and are redeemable upon a holder ceasing to be a director of PetroTal. No common shares will be issued under the DSU plan, as they are settled in cash at the prevailing market price and valued at the closing share price on the reporting date. For the year ended December

31, 2024, the Company recognized $0.1 million of DSU expense in administrative expense and contributed surplus (December 31, 2023: $0.8 million). The following table details the PSU and DSU activity:

	Performance Share Units	Deferred Share Units
Balance at January 1, 2023	19,727,168	2,651,754
Additions	9,038,663	1,292,000
Issued	(7,707,440)	—
Forfeited	(256,471)	—
Exercised/settled	—	(151,260)
Balance at December 31, 2023	20,801,920	3,792,494
Additions	8,930,275	2,044,369
Issued	(9,910,871)	—
Forfeited	(1,542,321)	—
Exercised/settled	—	(765,428)
Balance at December 31, 2024	18,279,003	5,071,435

17. REVENUE NET OF ROYALTIES AND SOCIAL FUND

The Company's oil revenue is determined pursuant to the terms of various sales agreements. The transaction price for crude is based on the commodity price in the production month, adjusted for quality, allowable deductions and other factors. Commodity prices are based on market indices.

	Year Ended	
	December 31 2024	December 31 2023
Oil revenue	373,940	316,911
Royalty	(29,518)	(23,389)
Social fund (see Note 4)	(10,429)	(7,259)
Oil Revenue Net of Royalties and Social Fund	333,993	286,263

The Company sold 6,426,106 barrels with a net realized sales price of $58.19/bbl. in 2024, net of price discounts (2023: 5,263,485 barrels, net sales price of $60.21/bbl.).

18. GENERAL AND ADMINISTRATIVE EXPENSES

	Year Ended	
	December 31 2024	December 31 2023
Salaries and benefits	23,306	14,065
Legal, audit and consulting fees	12,933	9,459
Community support	2,968	3,100
Office rent and administrative	5,927	4,350
Share based compensation plans	3,151	4,364
Costs directly attributable to PP&E and operating expenses	(11,994)	(7,289)
Total	36,291	28,049

The Company's general and administrative expenses were $8.2 million higher in 2024 compared to 2023, due to an increase in salaries and headcount, higher professional fees and Environmental, Social, and Governance ("ESG") consulting expenses, partially offset by costs directly attributable to PP&E and operating expenses.

19. FINANCE EXPENSE

	Year Ended	
	December 31 2024	December 31 2023
Bond interest and fees amortization and other interest	1,986	16,183
Factoring costs	437	403
Lease interest	2,405	1,304
Accretion of decommissioning obligations	1,292	994
Interest income	(2,965)	(3,543)
Total	3,156	15,341

The Company's finance expense variance was $12.2 million lower compared to 2023, mainly due to the total repayment of capital, fees and interest associated with the senior debt bonds.

20. TRANSPORTATION EXPENSE

Direct transportation is comprised of diluent, barging, diesel, dry season freight and storage expenses. Diluent costs are required for sales to the Iquitos refinery.

	Year Ended	
	December 31 2024	December 31 2023
Diluent	4,931	6,857
Barging	6,200	3,475
Diesel	520	516
Dry season freight and storage	3,697	4,115
Total Direct Transportation	15,348	14,963

21. RELATED PARTY TRANSACTIONS

The Company had no related party transactions or off-balance sheet arrangements. The Company's key management includes the Directors and Officers.

	Year Ended	
	December 31 2024	December 31 2023
Salaries, incentives and short term benefits	2,021	1,846
Director's fees	1,322	1,014
Share-based compensation	1,736	2,430
Total	5,079	5,290

22. CAPITAL STRUCTURE

The Company's objective when managing capital is to ensure it has sufficient funds to maintain ongoing operations, to pursue the acquisition of oil and gas properties, and to maintain a flexible capital structure that optimizes the cost of capital at an acceptable risk. The Company manages its capital structure, which may include equity and debt, and adjusts it according to the funds available to support the exploration and development of its interests in its existing oil and gas properties, and to pursue other opportunities as they arise.

The Company defines its capital as follows:

	December 31 2024	December 31 2023
Equity	511,508	463,942
Working capital (current assets less current liabilities)	(90,989)	(121,649)
Total	420,519	342,293

23. TAXES

The Company's effective tax rate is impacted by the relative pre-tax income earned by the Company's operations in Canada, U.S., and Peru. The Company is subject to statutory tax rates of 23% in Canada, 21% in the U.S. and 32% in Peru (activities of the Company in Peru are subject to a 30% statutory tax rate plus 2% in accordance with Law 27343). The Company files federal income tax returns and local income tax returns in the various jurisdictions.

The tax at the effective rate differed from the tax at the statutory rate as follows:

	Year Ended	
	December 31 2024	December 31 2023
Earnings before income taxes	151,352	143,507
Canadian corporate tax rate	23%	23%
Expected income tax expense	34,811	33,007
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	(1,349)	1,408
Tax differential on foreign jurisdictions	6,440	10,212
Change in valuation allowance	—	(11,625)
Provision for income taxes	**39,902**	**33,002**

The deferred income tax balances are as follows:

	Year Ended	
	December 31 2024	December 31 2023
Deferred income tax asset:		
Property, plant, and equipment	—	7
Net operating loss carryover	1,013	4,119
Other tax pools	950	8,919
Deferred income tax asset	**1,963**	**13,045**
Deferred income tax liability:		
Property, plant, and equipment	(81,082)	(58,554)
Derivative assets and liabilities	3,271	(2,372)
Preoperative expenses	1,912	2,549
Net operating loss carryover	41	2,156
Other tax pools	3,310	1,112
Deferred income tax liability	**(72,548)**	**(55,109)**

The Company recognized the net tax amount related to Net Operating Losses ("NOLs") and deferred tax liabilities in Canada, Peru and the US. As of December 31, 2024, the Company consumed all losses in Canada (December 31, 2023: $21 million) and all losses in Peru related to Bretana (December 31, 2023: $7 million). The US has $4 million tax losses remaining (December 31, 2023: $1 million). The US non-capital losses can be carried forward indefinitely.

Ucawa has $82 million in tax losses at the end of December 31, 2024, but no related deferred tax asset has been recognized. These losses are being carried forward and are available to offset against future tax gains.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as of December 31, 2024 is approximately $22 million (December 31, 2023: $29 million).

24. COMMITMENTS

At December 31, 2024, the Company holds the following letters of credit guaranteeing its commitments in exploration block 107:

Block	Beneficiary	Amount	Commitment	Expiration
107	Perupetro S.A.	$1,500	1st exploration well, minimum work 5th exploratory period	May 2026
107	Perupetro S.A.	$1,500	2nd exploration well, minimum work 5th exploratory period	May 2026
		$3,000		

PetroTal also signed two Technical Evaluation Agreements with Perupetro in December 2024. The Technical Evaluation Agreements for Blocks 97 and 98 are located in the vicinity and on trend with PetroTal's Block 131, as well as the Aguaytia and Agua Caliente fields in Peru's Ucayali Basin. Contractual commitments will be executed in two 12-month phases, and mainly include geological and geophysical studies such as seismic imaging, geochemical modeling and hydrocarbon potential evaluation reports.

The Company progressed its preventive riverbank erosion control program aimed to protect the Bretana field and nearby community. The estimated total project cost has a range of $65 million to $75 million, which will be allocated approximately 65% to operating expense and 35% to capital expenditures during the next years. This program represents a significant operational and environmental commitment, and indicates a proactive approach to environmental stewardship for a permanent solution for the riverbank erosion.

As part of Ucawa Energy S.A.C. asset acquisition, a tax administrative and a judicial legal case were considered as possible, with a total legal contingency of approximately $2.5 million. According to clause 12.5 in the Purchase Agreement, the seller (CEPSA S.A.) is obligated to indemnify PetroTal of any legal action, and/or fines if applicable.

25. SUBSEQUENT EVENTS

On January 14, 2025, Banco Interamericano de Finanzas extended the exploratory block 107 letters of credit to February 2027.

In January 2025, PetroTal entered into hedged trades that are costless collars with a cap and 1.8 million barrels through January 2026. The hedges were completed at a floor strike price of $65/bbl. and a ceiling strike price of approximately $80/bbl. In addition, a cap was placed at $100/bbl. to limit credit exposure in the event Brent prices rise above $100/bbl.

On February 20, 2025, the Company declared a cash dividend of $0.015 per common share to be paid March 14, 2025.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2024 and 2023

PetroTal

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MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the operating results and financial condition of PetroTal Corp. ("PetroTal" or the "Company") for the years ended December 31, 2024 and 2023, is dated March 18, 2025, and should be read in conjunction with the Company's audited Consolidated Financial Statements (the "Financial Statements") and the Company's Annual Information Form ("AIF") for the years ended December 31, 2024 and 2023. The audited Financial Statements were prepared by management in accordance with International Financial Reporting Standards ("IFRS®") issued by the International Accounting Standards Board ("IASB"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada.

Financial figures throughout this MD&A are stated in thousands of United States dollars ("$" or "USD") unless otherwise indicated. This MD&A contains forward-looking statements that should be read in conjunction with the Company's disclosure under "Forward- Looking Statements and Business Risks".

1.CORPORATE OVERVIEW

PetroTal Corp. is a publicly-traded (TSX: TAL, AIM: PTAL, and OTCQX: PTALF) international oil and gas Company incorporated and domiciled in Canada, with management based in Houston, Texas and Lima, Peru. Through its subsidiaries in Peru, the Company is currently engaged in the ongoing development of hydrocarbons at Block 95 and Block 131. PetroTal also has exploration prospects and leads in Block 107.

The Bretana oil field is located within Block 95 in the Maranon Basin of northern Peru. To date, this basin has produced more than one billion barrels ("bbls.") of oil. Approximately 70% of the oil in the Maranon Basin has been produced from the Vivian formation, which is known as a high-quality oil reservoir characterized by high permeability and strong aquifer support. Generally, this type of reservoir achieves the highest oil recoveries. The Bretana field, which produces from the Vivian formation, is currently the largest producing oil field in Peru. PetroTal holds a 100% working interest in Block 95 and the Bretana field; as of year-end 2024, Bretana's Proved plus Probable oil reserves were independently assessed at 107.9 million bbls.

In 2024, PetroTal closed the acquisition of a 100% working interest in Peru's Block 131, which contains the producing Los Angeles field. Block 131 is located in the Ucayali Basin of central Peru, where the most notable hydrocarbon discovery is the Camisea gas field. The Camisea project, which came onstream in 2004, mainly produces natural gas feedstock for the Peru LNG export facility. However, the Ucayali Basin also contains a number of small, light oil fields which have been producing since the mid-1900's. The Los Angeles field, which was discovered in 2013, produced an average of approximately 800 barrels of oil per day ("bopd.") of light oil in 2024; as of year-end 2024, the field's Proved plus Probable oil reserves were independently assessed at 5.8 million bbls. In December 2024, PetroTal signed two Technical Evaluation Agreements surrounding Block 131, where a number of light oil exploration leads and prospects have already been identified by previous operators. The Company is currently conducting geological and geophysical evaluation of the acreage, with a view to advancing exploration activities in the coming years.

2. OVERVIEW AND SELECTED INFORMATION

The following table summarizes key financial and operating highlights associated with the Company's performance for the periods ended December 31, 2024 and December 31, 2023, along with 2024 quarters.

RESULTS AT A GLANCE

	Year Ended		Three Months Ended			
	2024	2023	December 31, 2024	September 30, 2024	June 30, 2024	March 31, 2024
Financial						
Oil revenue	$373,940	$316,911	$91,421	$78,850	$103,086	$100,583
Royalties[1]	($39,947)	($30,648)	($13,022)	($7,433)	($9,991)	($9,500)
Net operating income [2]	$274,325	$238,854	$57,458	$57,233	$80,025	$79,610
Erosion expense	$10,117	—	$9,569	$548	—	—
Commodity price derivatives (gain) loss	$10,424	$12,479	($2,726)	$21,481	$3,306	($11,638)
Net income	$111,450	$110,505	$21,242	$7,179	$35,405	$47,619
Basic earnings per share ($/share)	$0.12	$0.12	$0.02	$0.01	$0.04	$0.05
Capital expenditures	$162,827	$108,453	$50,589	$43,019	$38,867	$30,352
Operating						
Average production (bopd.)	17,785	14,248	19,142	15,203	18,290	18,518
Average sales (bopd.)	17,558	14,421	19,087	14,760	18,050	18,347
Average Brent price ($/bbl.)[3]	78.98	81.53	73.42	77.74	83.87	81.01
Contracted sales price ($/bbl.)	79.15	80.54	73.16	78.58	83.92	81.14
Netback ($/bbl.) [2]	42.68	45.39	32.71	41.74	48.72	47.68
Free funds flow [4]	$74,145	$107,192	($10,422)	$6,537	$36,334	$41,696
Balance Sheet						
Cash and restricted cash	$114,528	$111,299	$114,528	$133,072	$95,859	$85,151
Working capital	$90,989	$119,299	$90,989	$124,439	$144,133	$136,472
Total assets	$810,467	$658,286	$810,467	$746,131	$720,700	$700,360
Current liabilities	$135,172	$83,883	$135,172	$112,665	$93,283	$95,572
Equity	$511,508	$463,942	$511,508	$503,756	$509,921	$488,917

(1) Royalties include 2.5% community social trust initiative.
(2) Net operating income ("NOI") and Netback represent revenues less royalties, operating expenses (excludes erosion expense) and direct transportation.
(3) bbl. = barrel
(4) Free funds flow does not have standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities. See "Non-GAAP Measures" section.

3. 2024 HIGHLIGHTS

The Company reached several key operational and financial achievements as described below:

Q4 2024 Highlights

- Oil production of 1.8 million bbls., an average of 19,142 bopd, an increase of 26% from 15,203 bopd. in Q3 2024, and a 29% increase from 14,865 bopd. in Q4 2023. At December 31, 2024, the Company has 25 producing oil wells and 4 water disposal wells;
- Oil sales allocations were 89.2% as exports through Brazil, 9.7% to the Iquitos refinery, and 1.1% from Ucawa;
- PetroTal completed drilling horizontal well 21H ("21H") in November 2024. This well was brought onstream on November 17, 2024 at a flush production rate of 7,144 bopd., before producing at an average rate of 2,522 bopd. over the next 30 days. Well 21H was completed on time and on budget, at a cost of approximately $14.4 million;
- PetroTal completed drilling horizontal well 22H ("22H") in December 2024. This well was brought onstream on January 9, 2025, producing an average of 4,344 bopd. over the next 30 days, while achieving a peak daily rate of 7,025 bopd. Well 22H was also completed on time and on budget, at a cost of approximately $12.0 million;
- In October 2024, PetroTal executed an agreement to acquire a drilling rig from a Houston-based equipment Company. The purchase of the rig was financed through a lease agreement with a Peruvian bank, for a term of 36 months at a payment of approximately $0.5 million per month. PetroTal intends to import the rig to Peru in Q1 2025;
- In December 2024, PetroTal signed two Technical Evaluation Agreements with Perupetro. The Technical Evaluation Agreements for Blocks 97 and 98 are located in the vicinity and on trend with PetroTal's Block 131, as well as the Aguaytia and Agua Caliente fields in Peru's Ucayali Basin. These new evaluation contracts offer growth potential in proven exploration acreage near PetroTal's existing operations in the area; and,
- In December 2024, PetroTal signed a contract extension with Perupetro for the exploration Block 107, in Peru's Ucayali Basin. The extension of the Fifth Exploration Period will now last until February 2027, providing ample time to undertake an exploration program at the Osheki-Kametza prospect.

2024 Operational Highlights

- Oil production of 6.5 million bbls. in 2024, representing an average of 17,785 bopd., an increase of 25% from 14,248 bopd. (5.2 million bbls.) in 2023;
- Oil sales allocations were 88.4% as exports through Brazil, 11.3% to the Iquitos refinery, and 0.3% from Ucawa;
- PetroTal drilled seven development wells at Bretana in 2024, compared to three development wells in 2023; and
- PetroTal's 2024 annual independent reserves assessment, as prepared by Netherland Sewell and Associates, Inc. ("NSAI") shows increases in all reserve categories, combined heavy plus light oil:
    - Proved ("1P") reserves increased by 40% to 67.1 million bbls. Net present value discounted at 10% ("NPV-10") after tax is $1.1 billion;

- ◦ Proved plus Probable ("2P") reserves increased by 14% to 113.7 million bbls., with an NPV-10 after tax valuation of $1.8 billion; and,
- ◦ Proved plus Probable plus Possible ("3P") reserves increased by 7% to 213.3 million bbls., with an NPV-10 after tax valuation of $2.8 billion.

2024 Financial Highlights

- The Company generated revenue of $373.9 million (6.4 million bbls. sold, 17,558 bopd., $58.19/bbl.) compared to $316.9 million (5.2 million bbls. sold, 14,421 bopd., $60.21/bbl.) in 2023;
- Royalties paid to the Peruvian government in 2024 were $29.5 million ($4.59/bbl., 7.9% of revenues) compared to $23.4 million ($4.44/bbl., 7.4% of revenues) in 2023. Contributions for the 2.5% community social trust fund represented $10.4 million in 2024, as compared to $7.3 million in 2023;
- Capital expenditures (“Capex”) totaled $161 million in 2024, primarily associated with the drilling of wells during the year, the expansion of fluid-handling facilities capacity in the Bretana field, and field infrastructure;
- PetroTal entered into a hedging agreement during the quarter, covering the future sale of 1.8 million barrels as of December 31, 2024. The costless collars have a floor price of $65.00/bbl. and a ceiling of $84.25/bbl., with a cap of $104.25/bbl.;
- Generated 2024 EBITDA and free funds flow of $227.9 million ($35.47/bbl.) and $74.1 million ($11.54/bbl.), respectively;
- Net operating income was $274.3 million ($42.68/bbl.) compared to $238.9 million ($45.39/bbl.) in 2023;
- PetroTal ended the year with total cash of $114.5 million ($102.8 million unrestricted), compared to $111.3 million ($90.6 million unrestricted) in 2023; and,
- PetroTal continued its sustainable shareholder capital return policy. In 2024 PetroTal paid dividends totaling $60.5 million and repurchased 8.8 million shares ($4.9 million), compared to dividends paid of $55.6 million and repurchased shares of 11.3 million ($6.5 million) in 2023.

December 31, 2024 Subsequent Events

- On January 14, 2025, Banco Interamericano de Finanzas extended the exploratory block 107 letters of credit to February 2027;
- In January 2025, PetroTal entered into hedged trades that are costless collars with a cap and 1.8 million barrels through January 2026. The hedges were completed at a floor strike price of $65/bbl. and a ceiling strike price of approximately $80/bbl. In addition, a cap was placed at $100/bbl. to limit credit exposure in the event Brent prices rise above $100/bbl; and,
- On February 20, 2025, the Company declared a cash dividend of $0.015 per common share to be paid March 14, 2025.

4. ASSET ACQUISITION

On November 29, 2024, PetroTal closed the acquisition of a 100% working interest in Peru’s Block 131, as originally disclosed on May 8, 2024, pursuant to which the Company acquired all of the issued and outstanding shares of Ucawa Energy S.A.C. (formerly CEPSA Peruana, S.A.C. or “CEPSA Peru”). Cash consideration of $6.7 million paid for the asset was partially offset by the assumption of a cash balance of $5 million on closing. The cash balance reflects the cumulative cash flow from this asset between the effective date of the acquisition to its closing date on November 29, 2024. The amounts recognized on the date of acquisition to identifiable net assets were as follows:

	November 29, 2024
Net Assets acquired	
Cash & Cash equivalents	4,988
Trade receivables and other assets	5,179
Property, plant and equipment, net	12,036
Trade and other payables	(1,926)
Decommissioning liabilities	(13,589)
Total Net Asset acquired	**6,688**
Purchase consideration	6,688
Total Purchase consideration	**6,688**

The acquisition of Block 131 represents an important milestone for PetroTal, and a pivotal step in the Company's growth strategy. More importantly, Block 131 diversifies the production base within Peru, establishing a new platform for production and reserves growth. PetroTal's technical team has already identified numerous synergies between the Block 131 assets and existing operations at Block 95. The Company also plans to apply modern drilling techniques at the Los Angeles field, which has significant unutilized facility capacity.

5. OUTLOOK AND GROWTH STRATEGY

STRATEGY OUTLOOK

PetroTal's near-term strategy is focused on responsible stewardship of the Bretana Norte oil field, balancing priorities for key stakeholder groups while maximizing value for shareholders. Specifically, the key objectives of PetroTal's 2024 capital program included:

- Continued migration of 2P reserves into 1P and PDP categories;
- Development of new export routes to maximize value for our product, while minimizing operational risk;
- Maintaining a debt-free balance sheet; and,
- Returning free cash flow to shareholders through stable dividends and share buybacks when appropriate.

As of December 31, 2024, PetroTal has drilled a total of 22 development wells at Bretana, plus 4 water injection wells. The ongoing 2024 development program is consistent with the Company's year-end reserve report, which contemplated a field development plan consisting of 32 production wells in the 2P case. Remaining recoverable reserves of approximately 107.9 million barrels are expected to be produced prior to the Block 95 license contract expiry in 2041. The 3P case includes recoverable reserves upside to 207 million barrels, mainly through the drilling of additional development locations, and the extension of the Block 95 license contract.

PetroTal is continuously evaluating alternative development strategies which may lead to improved recovery factors and/or acceleration of undeveloped reserves, including infill drilling, extended reach horizontal wells, and multilateral drilling. For example, in Q3 2024, the Company drilled its first lateral into the Upper Vivian sand ("VS1") at Bretana, where a brief production test flowed 320 bopd. This zone, which PetroTal's independent reserve evaluator estimates may contain more than 20% of the original oil in place at the Bretana field, was included in the Company's 3P reserves at year-end 2024.

Another key strategic priority is to secure new export routes throughout Peru, which will facilitate execution of PetroTal's full 2P and 3P development plans. The company has identified four potential new transportation options in Peru, which could increase sales capacity by up to 20,000 bopd. over the next two to three years. In Q3 2024, PetroTal initiated a pilot shipment of Bretana crude to the Ecuador Pipeline ("OCP"); although the pilot was ultimately hampered by unusually low river levels.

Finally, as part of PetroTal's unique value proposition to investors, the Company is committed to returning a portion of its free cash flow to shareholders through dividends and share buybacks. With relatively short payback periods on new production wells, PetroTal is capable of generating significant free cash flow which can be used to fund its ongoing development program while supporting returns of capital that have averaged between 11% and 18% on an annualized basis.

The 2024 capital budget was based on an estimated average annual Brent oil price forecast of $77/bbl.

Growth Strategy

PetroTal's medium-term growth strategy is currently based on the reinvestment of free cash flow from Bretana into undeveloped assets elsewhere in Peru, where the Company has an established track record of operational success. The key objectives of our medium-term growth strategy include:

- Reach and extend Bretana plateau while developing other assets;
- Optimize cost structure through operating synergies;
- Achieve $2 billion in market capitalization through expansion; and,
- Continue to return free cash flow to shareholders.

As the main funding driver of PetroTal's growth ambitions, the Bretana field remains critical to both the medium- and long-term strategy of the Company. Consistent with the performance of the field over the past few years, PetroTal continues to forecast significant free cash flow from Bretana, which will be used in part to fund the development of new assets elsewhere.

Employing its knowledge base and technical expertise in Latin America, the Company is also executing its growth strategy by sourcing inorganic M&A opportunities to create long-term value for shareholders. PetroTal closed its first acquisition in Peru on November 29, 2024, assuming control of the producing Block 131. The Company is currently finalizing development plans for the asset, including potentially drilling new production wells in 2025.

PetroTal recognizes that balance sheet flexibility is a key focus of investors, and remains a priority for the Company. Supported by the strong historical performance of the Bretana field, PetroTal has the ability to source debt capital at favorable terms, allowing for incremental investment in projects that align with the Company's strategic objectives when appropriate.

Environmental, Social and Governance (“ESG”) Strategy

PetroTal believes in creating long-term value for our shareholders, employees, suppliers, communities, customers, financial entities, industry associations, international certification bodies and organizations, media, and the government, as well as ensuring economic value, safety for people and the environment, and creating a better future for all. PetroTal's ESG vision is: “To create value and generate more opportunities for the benefit of all”. The steps to measure our success are:

- Develop measurable goals for 2025 and 2030 that will be built and reviewed with the participation of various departments throughout the Company;
- Collaborate with government entities and key stakeholders to promote the efficient and transparent utilization of resources, including the 2.5% social fund and other resources, aimed at promoting strong governance frameworks, mitigating risks of corruption and fund mismanagement, and enhancing institutional capacity and technical expertise;
- Continuously update initiatives to achieve Company goals;
- The Sustainable Development Goals (“SDG”) will be included, to which PetroTal contributes through its sustainability plan to 2030;
- Committed to climate action, the Company aims to implement methodologies that prevent deforestation, minimize its carbon footprint and support projects with zero net biodiversity loss. It prioritizes ecosystem restoration and promotes the sustainable use of local natural resources, while actively evaluating new technologies to eliminate direct emissions in its operations;
- Implement effective due diligence processes, awareness and training to prevent possible human rights violations, focusing efforts on the value chain;
- Develop and promote talent in PetroTal, the community, and within our suppliers; and,
- Engage in constant dialogue with our stakeholders to identify opportunities for collaboration, address concerns and doubts, build awareness, improve our performance, and prevent conflicts.

Exploratory Block 107 – Osheki-Kametza

PetroTal has a 100% working interest in the 623,280 acre block located in the Ucayali basin of Peru. There are several prospective features, the largest being the Osheki-Kametza prospect. Osheki-Kametza has the potential to contain in place volumes of 970.7 million barrels of oil equivalent ("mmboe") according to the Company's independent reservoir engineers, NSAI. Resource estimates are based on maps generated from seismic acquired in 2007 and 2014 and partially de-risked with a new 3D geologic model supporting Cretaceous age reservoirs with high quality Permian source rocks. The Company continues to work on the necessary permits and complete further technical work for the Osheki-Kametza prospect which will allow PetroTal to consider progressing towards a drilling recommendation in 2026. Perupetro extended the Company's Block 107 exploratory license to February 2027. The block is in a farm out process to acquire a partner, which is necessary for undertaking the drilling commitments.

6. SELECTED FINANCIAL INFORMATION

6.1 FINANCIAL SUMMARY

		2024		Q4-2024		Q3-2024		Q2-2024		Q1-2024	
($ thousands)		$/bbl.		$/bbl.		$/bbl.		$/bbl.		$/bbl.	
PRODUCTION:	Average Production (bopd.)		17,785		19,142		15,203		18,290		18,518
SALES:	Average sales (bopd.)		17,558		19,087		14,760		18,050		18,347
	Total sales (bbls.)		6,426,106		1,756,030		1,357,961		1,642,578		1,669,537
	Average Brent price	$78.98		$73.42		$77.74		$83.87		$81.01	
Weighted contracted sales price, gross		$79.15		$73.16		$78.58		$83.92		$81.14	
LESS:	Tariffs, fees and differentials	($20.96)		($21.10)		($20.52)		($21.15)		($20.89)	
	Realized sales price, net	$58.19		$52.06		$58.06		$62.76		$60.25	
REVENUES:	Oil revenue (1)	$58.19	$373,940	$52.06	$91,421	$58.06	$78,850	$62.76	$103,086	$60.25	$100,583
LESS:	Royalties (2)	$6.22	$39,947	$7.42	$13,022	$5.47	$7,433	$6.08	$9,991	$5.69	$9,500
	Operating expense (excl. Erosion)	$6.90	$44,320	$7.88	$13,843	$8.23	$11,176	$6.10	$10,023	$5.56	$9,278
	Direct Transportation:										
	Diluent	$0.77	$4,931	$0.14	$248	$0.90	$1,218	$1.16	$1,898	$0.94	$1,567
	Barging	$0.96	$6,200	$1.89	$3,317	$0.68	$927	$0.58	$951	$0.60	$1,005
	Diesel	$0.08	$520	$0.05	$81	$0.13	$173	$0.11	$186	$0.05	$80
	Dry Season Freight/ Storage/Inventory	$0.58	$3,697	$1.97	$3,452	$0.51	$690	$0.01	$12	($0.27)	($457)
	Total Transportation	$2.39	$15,348	$4.05	$7,098	$2.22	$3,008	$1.86	$3,047	$1.32	$2,195
NET OPERATING INCOME (NOI)		$42.68	$274,325	$32.71	$57,458	$42.14	$57,233	$48.72	$80,025	$47.68	$79,610
	NOI as % of Revenue		*73.4%*		*62.9%*		*71.9%*		*77.6%*		*79.1%*
Erosion Expense		$1.57	$10,117	$5.45	$9,569	$0.40	$548	$—	$—	$—	$—
General and administrative expense		$5.65	$36,291	$4.86	$8,534	$6.75	$9,160	$6.41	$10,528	$4.83	$8,070
Commodity price derivative loss (gain)		$1.62	$10,424	($1.55)	($2,726)	$15.82	$21,481	$2.01	$3,306	($6.97)	($11,638)
Financial expense (gain)		$0.49	$3,156	$1.19	$2,096	($0.23)	($311)	$0.62	$1,018	$0.21	$353
Income tax expense (gain)		$6.21	$39,902	($0.12)	($209)	$4.45	$6,038	$8.81	$14,470	$11.74	$19,602
Depletion, depreciation and amortization		$9.69	$62,242	$10.54	$18,504	$9.64	$13,092	$9.32	$15,310	$9.19	$15,338
Foreign exchange loss (gain)		$0.12	$743	$0.25	$448	$0.03	$46	($0.01)	($14)	$0.16	$264
NET INCOME			$111,450		$21,242		$7,179		$35,407		$47,621
FREE FUNDS FLOW			$74,145		($10,422)		$6,537		$36,334		$41,696

(1) Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

(2) Royalties include 2.5% community social trust initiative.

Note: Free Funds Flow calculation methodology was changed in Q2 2024 and for prior periods to include adjustments for foreign exchange and share based compensation to better measure the Company's generated cash. Q1 2024 previously reported was $52,561 vs. $41,696 with the new methodology.

		2023		Q4-2023		Q3-2023		Q2-2023		Q1-2023	
($ thousands)		$/bbl.		$/bbl.		$/bbl.		$/bbl.		$/bbl.	
PRODUCTION:	Average Production (bopd.)		14,248		14,865		10,909		19,031		12,193
SALES:	Average sales (bopd.)		14,421		15,033		11,553		18,483		12,618
	Total sales (bbls.)		5,263,485		1,383,061		1,062,851		1,681,962		1,135,611
	Average Brent price	$81.53		$82.21		$84.65		$77.29		$82.51	
Weighted contracted sales price, gross		$80.54		$81.05		$84.31		$77.88		$80.32	
LESS:	Tariffs, fees and differentials	($20.33)		($20.28)		($19.25)		($21.26)		($20.01)	
	Realized sales price, net	$60.21		$60.77		$65.05		$56.61		$60.31	
REVENUES:	Oil revenue (1)	$60.21	$316,911	$60.77	$84,046	$65.05	$69,142	$56.61	$95,229	$60.31	$68,494
LESS:	Royalties(2)	$5.82	$30,648	$7.00	$9,676	$5.49	$5,835	$5.29	$8,899	$5.49	$6,238
	Operating expense (excl. Erosion)	$6.16	$32,446	$7.24	$10,010	$8.45	$8,982	$4.22	$7,100	$5.60	$6,354
	Direct Transportation:										
	Diluent	$1.30	$6,857	$1.46	$2,020	$1.72	$1,829	$0.98	$1,641	$1.20	$1,368
	Barging	$0.66	$3,475	$0.60	$828	$0.80	$845	$0.53	$896	$0.80	$906
	Diesel	$0.10	$516	$0.10	$142	$0.13	$141	$0.07	$120	$0.10	$113
	Dry Season Freight/ Storage/Inventory	$0.78	$4,115	$1.45	$2,001	$1.99	$2,114	$—	$—	$—	$—
	Total Transportation	$2.84	$14,963	$3.61	$4,991	$4.64	$4,929	$1.58	$2,657	$2.10	$2,387
NET OPERATING INCOME (NOI)		$45.39	$238,854	$42.92	$59,369	$46.47	$49,396	$45.53	$76,573	$47.12	$53,515
	NOI as % of Revenue		*75.4%*		*70.6%*		*71.4%*		*80.4%*		*78.1%*
General and administrative expense		$5.33	$28,049	$6.21	$8,588	$6.92	$7,355	$3.89	$6,548	$4.90	$5,559
Commodity price derivative loss (gain)		$2.37	$12,479	$8.43	$11,662	($11.95)	($12,701)	$3.73	$6,272	$6.38	$7,247
Financial expense		$2.91	$15,341	$2.28	$3,150	$1.12	$1,187	$1.22	$2,046	$7.89	$8,958
Income tax expense		$6.27	$33,002	$2.95	$4,076	$18.30	$19,445	$1.64	$2,751	$5.93	$6,730
Depletion, depreciation and amortization		$7.56	$39,801	$8.33	$11,527	$7.49	$7,962	$7.23	$12,154	$7.18	$8,158
Foreign exchange (gain) loss		($0.06)	($323)	($0.84)	($1,163)	$0.74	$789	$0.10	$167	($0.10)	($116)
NET INCOME			$110,505		$21,529		$25,359		$46,635		$16,979
FREE FUNDS FLOW			$107,192		$19,767		$26,560		$45,044		$15,821

(1) Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

(2) Royalties include 2.5% community social trust initiative.

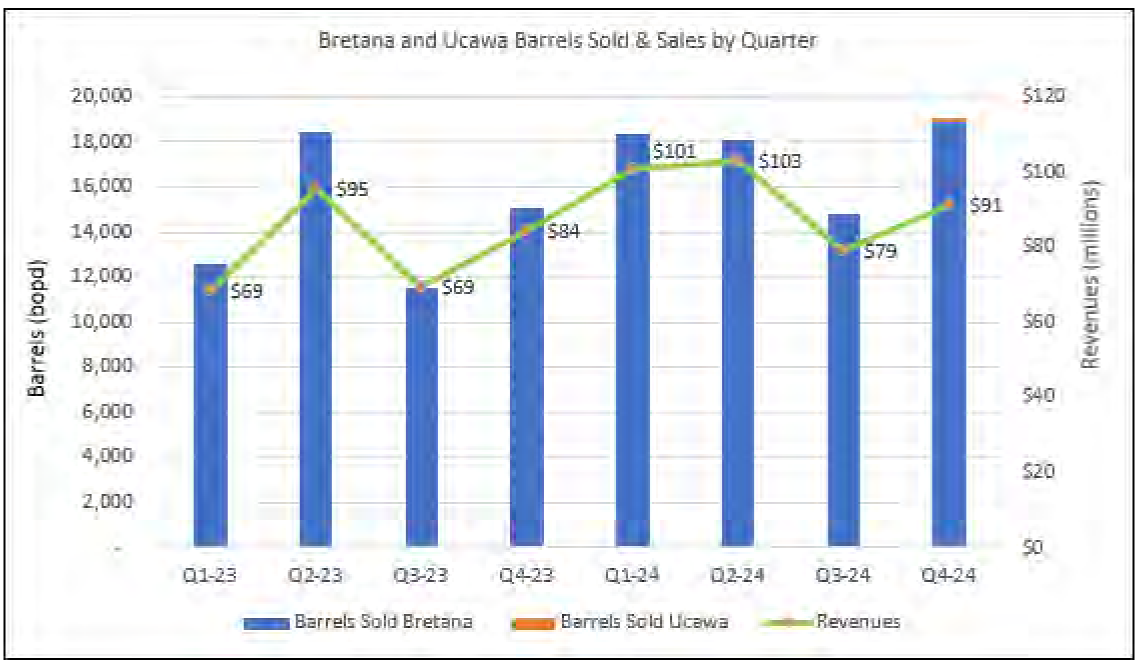
Note: Free Funds Flow calculation methodology was changed in Q2 2024 and for prior periods to include adjustments for foreign exchange and share based compensation to better measure the Company's generated cash. Previously reported was 2023: $90,674; Q4 2023: $8,127; Q3 2023: $36,944; Q2 2023: $37,697; and Q1 2023 $7,906.

EARNINGS STATEMENT INFORMATION

Oil sales in 2024 increased by 22% to 6.4 million bbls. (17,558 bopd), compared to 5.3 million bbls. (14,421 bopd.) in 2023. Sales were 1.8 million bbls. (19,087 bopd.) in Q4 2024 compared to 1.4 million bbls. (15,033 bopd.) in Q4 2023.

The Company sells oil at three sales points: the local Iquitos refinery, exports through Brazil, and the Northern Peruvian Pipeline ("ONP"). In 2024, 88.4% of PetroTal's oil sales were through the Brazil export route and 11.3% to the Iquitos refinery. Sales to the Iquitos refinery are priced at the prevailing Brent oil price less a quality differential discount and barge transportation charges. Included in the Iquitos refinery sales during the month of December 2024 was 18,741 bbls. related to the new acquisition of Ucawa (0.3% of the total sales in 2024). Oil sales exported through Brazil are on a freight on board ("FOB") Bretana basis, at the forecasted Brent oil price in three months, less a fixed amount to cover all transportation and sales costs, including the quality differential.

Sales to the ONP (Saramuro pump station) have been curtailed since February 2022, pursuant to Petroperu's inability to fulfill terms of the sales agreement. Sales to Petroperu at Saramuro for transportation through the ONP and onward to the Bayovar port, are priced based on the forecasted Brent oil price in eight months, less a quality differential, and is net of all pipeline and marketing fees. When the oil is ultimately sold by Petroperu at Bayovar, PetroTal is subject to a valuation adjustment based on the actual price achieved by Petroperu, whether higher or lower than the original forecasted price.



Royalties and social fund increased to $39.9 million ($6.22/bbl.) in 2024 from $30.6 million ($5.82/bbl.) in 2023, and in Q4 2024 increased to $13.0 million ($7.42/bbl.) from $9.7 million ($7.00/bbl.) in Q4 2023. Royalties for the Bretana oilfield are calculated on production, less transportation costs, starting at 5% based on production of 5,000 bopd. or less and 20% when production reaches 100,000 bopd. or more, increasing on a straight-line basis. Royalty determination is calculated on an individual block basis, based either on production scales or on economic results.

Operating expenses in 2024 were $44.3 million ($6.90/bbl.), as compared to $32.4 million ($6.16/bbl.) in 2023, and in Q4 2024 were $13.8 million ($7.88/bbl.) versus $10.0 million ($7.24/bbl.) in Q4 2023. Higher oil production resulted in higher operating costs mainly related to: $4.3 million in support and subcontracted services, $3.1 million of general and administrative expense allocation, and $4.5 million in community relations, monitoring costs and riverbank maintenance.

Direct Transportation expenses in 2024 totaled $15.3 million ($2.39/bbl.), representing barging and diluent blending costs, as compared to $15.0 million ($2.84/bbl.) in 2023, and in Q4 2024 totaled $7.1 million ($4.05/bbl.) versus $5.0 million ($3.61/bbl.) in Q4 2023. Direct transportation costs include $3.7 million ($0.58/bbl.) in 2024, and $4.1 million ($0.78/bbl.) in 2023 for storage and dry season freight due to low river levels. Diluent costs fluctuate as a result of blending requirements for oil delivered to the Iquitos refinery.

	Year Ended	
	December 31, 2024	December 31, 2023
Diluent	4,931	6,857
Barging	6,200	3,475
Diesel	520	516
Dry season freight and storage	3,697	4,115
Total Direct Transportation	15,348	14,963

General and administrative ("G&A") expenses in 2024 were $36.3 million ($5.65/bbl.), as compared to $28.0 million ($5.33/bbl.) in 2023, and $8.5 million ($4.86/bbl.) in Q4 2024 versus $8.6 million ($6.21/bbl.) in Q4 2023. As production increases, per barrel G&A costs generally decrease.

	Year Ended	
	December 31, 2024	December 31, 2023
Salaries and benefits	23,306	14,065
Legal, audit and consulting fees	12,933	9,459
Community support	2,968	3,100
Office rent and administrative	5,927	4,350
Share based compensation plans	3,151	4,364
Costs directly attributable to PP&E and operating expenses	(11,994)	(7,289)
Total	36,291	28,049

The Company allocated $12.0 million of G&A in 2024 to capital projects and operating expenses, compared to $7.3 million in 2023.

Depletion, Depreciation and Amortization (“DD&A”) for 2024 was $62.2 million ($9.69/bbl.) as compared to $39.8 million ($7.56/bbl.) in 2023, and in Q4 2024 totaled $18.5 million ($10.54/bbl.) versus $11.5 million ($8.33/bbl.) in Q4 2023. DD&A is calculated based on capital invested plus expected future capital using the unit of production method over their proved plus probable reserves.

Commodity price derivative loss of $10.4 million in 2024 is net fair value change of outstanding embedded derivatives, compared to $12.5 million derivative loss in 2023. The oil sales agreement with Petroperu for sales into the ONP are subject to oil price variations when sold by Petroperu upon arrival at the Bayovar port. The loss is non-cash and is contingent upon the eventual sale of oil volumes. Until a sale occurs, no payment is required. Moreover, if oil prices rise, the projected loss could decrease, potentially benefiting the Company's financial position.

Foreign exchange loss in 2024 was $743 thousand compared to $323 thousand gain in 2023, and a $448 thousand loss in Q4 2024 compared to a $1.2 million gain in Q4 2023, due to fluctuations in relative currency positions and transactions.

Income tax of $39.9 million was recorded in 2024 compared to $33.0 million in 2023.

Financial expense was $3.2 million in 2024, mainly related to financial service fees and accretion of decommissioning obligation, as compared to $15.3 million in 2023. Finance expense in 2023 was higher due to debt bonds balances, paid during the same year.

6.2 BALANCE SHEET INFORMATION

BALANCE SHEET - SUMMARIZED

	December 31, 2024	September 30, 2024	June 30, 2024	March 31, 2024	December 31, 2023
($ thousands)					
Current Assets					
Cash	$102,783	$121,328	$84,116	$62,498	$90,568
Restricted cash	$5,745	$5,744	$5,743	$16,653	$14,731
VAT receivable	$23,023	$20,032	$12,376	$9,034	$9,709
Trade and other receivables	$65,832	$47,011	$93,325	$93,402	$58,602
Inventory	$13,570	$23,560	$14,960	$16,525	$12,792
Prepaid expenses	$13,901	$16,199	$19,933	$15,867	$7,462
Derivative assets	$1,307	$3,230	$6,963	$18,065	$9,318
Total Current Assets	$226,161	$237,104	$237,416	$232,044	$203,182
Restricted cash	$6,000	$6,000	$6,000	$6,000	$6,000
Trade Receivable long-term	$19,279	$20,439	$19,985	$20,514	$20,370
VAT receivables and deferred taxes	$4,292	$3,180	$2,769	$14,659	$15,271
PP&E and E&E, net	$547,424	$479,369	$446,563	$422,559	$408,537
Prepaid expenses	$7,000	$—	$—	$—	$—
Derivative assets	$311	$39	$7,967	$4,584	$4,926
Total Non-current Assets	$584,306	$509,027	$483,284	$468,316	$455,104
Total Assets	$810,467	$746,131	$720,700	$700,360	$658,286
Current Liabilities					
Trade and other payables	$94,955	$83,725	$71,271	$85,446	$79,328
Income tax payable	$19,744	$25,228	$18,133	$8,260	$—
Lease liabilities	$10,426	$3,712	$3,879	$1,866	$4,555
Short-term debt	$10,047	$—	$—	$—	$—
Total Current Liabilities	$135,172	$112,665	$93,283	$95,572	$83,883
Leases and other long-term	$46,322	$24,298	$25,304	$28,083	$26,373
Deferred income tax liabilities	$72,548	$65,006	$65,762	$62,633	$55,109
Long-term derivative liabilities	$10,534	$14,910	$3,974	$3,599	$6,832
Decommissioning liabilities	$34,383	$25,496	$22,456	$21,556	$22,147
Total Non-current Liabilities	$163,787	$129,710	$117,496	$115,871	$110,461
Total Equity	$511,508	$503,756	$509,921	$488,917	$463,942
Total Liabilities and Equity	$810,467	$746,131	$720,700	$700,360	$658,286

Cash and liquidity

At December 31, 2024, the Company held cash of $102.8 million and restricted cash of $11.7 million, totaling $114.5 million, compared to $111.3 million at December 31, 2023. Working capital was $91.0 million at December 31, 2024 as compared to $119.3 million at December 31, 2023.

	December 31, 2024	December 31, 2023
Cash	102,783	90,568
Restricted cash current	5,745	14,731
Restricted cash non-current	6,000	6,000
Total Cash	114,528	111,299

Current restricted cash of $5.7 million, is primarily related to the social fund and letters of credit bank guarantees for Block 107 exploration wells. The $6.0 million of non-current restricted cash is related to permitted hedging programs.

In March 2023, Peru's President signed the Supreme Decree authorizing Perupetro S.A. to execute the amendment incorporating the 2.5% social trust fund (value of the monthly oil produced in Bretana's Block 95, less transportation, for the benefit of local communities) into the Block 95 license contract, effective and retroactive to January 1, 2022. For the years ended December 31, 2024 and 2023, the Company paid to the community $17.8 million and $0.2 million, respectively.

VAT receivable

	December 31, 2024	December 31, 2023
VAT receivable current	23,023	9,709
VAT receivable non-current	2,329	2,226
Total VAT receivables	25,352	11,935

Valued Added Tax ("VAT") in Peru is levied on the purchase of goods and services and is recoverable on sales of goods and services. The Company recovered $25.9 million during the year ended December 31, 2024 and expects to recover $23.0 million in the short-term.

Trade and other receivables

	December 31, 2024	December 31, 2023
Trade receivables	84,754	76,163
Other receivables	357	2,809
Total trade and other receivables	85,111	78,972
Represented as:		
Current receivables	65,832	58,602
Non-current receivables	19,279	20,370

At December 31, 2024, trade receivables represent revenue related to the sale of oil. The trade balance is mostly comprised of $22.0 million due from Petroperu ($2.7 million is short term and $19.3 million is long term), $58.7 million from export sales through Brazil and $4.0 million from Ucawa Energy S.A.C. customers (all of which is due short term). No credit losses on the Company's trade receivables have been incurred and all short-term receivables are current.

In Q4 2023, the Company reclassified a $22.6 million Petroperu receivable from short-term receivables to long-term receivables. The long-term receivable was discounted to a present value of $20.4 million that resulted in a charge to finance expense. At December 31, 2024, the value of this receivable was $19.3 million.

Capital expenditures

	Year Ended	
	December 31,	December 31,
Drilling Program	103,870	67,271
Field Infrastructure	42,444	27,483
Fluid Handling Facilities (CPF)	10,454	6,247
Erosion Costs	154	3,205
Block 95	1,119	1,185
Block 107	1,422	1,547
Other	1,108	511
Exploration & development expenditures	160,571	107,449
SAP Project	2,425	1,004
Asset acquisition	9,078	—
Total capital expenditures	172,074	108,453

PetroTal invested $160.6 million in petroleum Capital Projects in 2024, an increase of $53.1 million compared to last year. The major capital expenditures were the costs associated with drilling wells 15H - 23H and water well 5WD at Bretana, along with the expansion of fluid handling capacity at the field and field infrastructure. Additionally, as a result of the asset acquisition, the Company added $9.1 million to its net PP&E balance as of December 31, 2024.

The Company continues to invest in a variety of community, social and regulatory ("CSR") initiatives. A strong emphasis on ESG is prevalent throughout all areas of our operations.

At December 31, 2024, the Company has $10.4 million of exploration and evaluation assets related to Block 95 and Block 107.

Inventory

	December 31, 2024	December 31, 2023
Oil inventory	2,676	813
Materials, parts and supplies	10,894	11,979
Total inventory	13,570	12,792

Oil inventory consists of the Company's oil barrels, which are valued at the lower of cost or net realizable value. Costs include operating expenses, royalties, transportation, and depletion associated with production. Costs capitalized as inventory will be expensed when the inventory is sold. At December 31, 2024, the oil inventory balance of $2.7 million consists of 85,863 bbls. of oil (including 3,466 bbls. from Ucawa Energy S.A.C.)

valued at $31.16/bbl. (December 31, 2023: $0.8 million, based on 35,320 bbls. of oil at $23.01/bbl.). Materials, parts, and supplies, including diluent, are expected to be consumed in the short-term.

	Barrels
Oil inventory at January 1, 2024	35,320
Asset acquisition	3,889
Production	6,509,275
Diluent added	53,680
Internal use (power generation) and other	(90,195)
Sales	(6,426,106)
Oil inventory at December 31, 2024	85,863

Trade and other payables

	December 31, 2024	December 31, 2023
Trade payables	39,201	25,037
Accrued payables and other obligations	55,754	54,291
Total trade and other payables	94,955	79,328

At December 31, 2024 and December 31, 2023, trade payables and other payables are primarily related to the drilling and completion of wells and construction of production processing facilities. The other obligations are mainly related to the 2.5% social fund for the benefit of local communities, which totaled to $5.0 million at December 31, 2024 ($12.2 million at December 31, 2023).

Included in the trade and other payables balance at December 31, 2024 are $2.0 million related to the asset acquisition of Ucawa.

Commodity Price Derivatives

The derivative asset is classified as a Level 2 fair value measurement. The ONP Saramuro agreement, signed with Petroperu during 2021, includes a clause for the purchase price adjustment. The initial sales price is based on the arithmetic average of the ICE Brent 8-month forward price. The realized price is based on the tender price of the oil that is sold at the Bayovar terminal. The purchase price adjustment represents the realized price less the initial sales price, and if negative, the Company will compensate Petroperu the amount, multiplied by the volume sold or arranged by Petroperu. If the purchase price adjustment is positive, the Company will be compensated by Petroperu in a similar manner.

The fair value change of the embedded derivative, considering an average future ICE Brent price marker differential, was recorded as a loss on commodity price derivatives at December 31, 2024.

	Year Ended December 31	
	2024	2023
Net derivative asset at beginning of period	7,412	20,370
Cash settlements	(5,904)	(478)
Realized loss	(3,741)	(2,256)
Unrealized loss	(6,683)	(10,224)
Net derivative asset (liability) at end of period	(8,916)	7,412
Represented as:		
Short-term derivative assets	1,307	9,318
Long-term derivative assets	311	4,926
Long-term derivative liabilities	(10,534)	(6,832)

Sales delivery / Executed month	Expected settlement month	Volume (bbls. in thousands)	Price range $/bbl.	Hedged range $/bbl.	Net Derivative Asset (Liability)
Peru Embedded Derivatives [1]					
Apr-21 to Feb-22	Sep-26 to Nov-28	1,882	62.49 to 85.26	67.95 to 69.44	(10,223)
Corporate Derivatives Hedging [2]					
Aug-24 and Oct-24	Jan-25 to Oct-25	1,655	—	65.00 to 104.50	1,307
				Net Derivative (Liability)	**(8,916)**

1) Embedded derivative related to original Petroperu sales agreement.

2) Corporate hedge program to cover a portion of 2024 and 2025 production.

1) Embedded derivative related to original Petroperu sales agreement.

For the year ended December 31, 2024, the Company realized true-up derivative gains from final sales at Bayovar of 0.5 million bbls. (during the year) for $5.9 million. At December 31, 2024, 1.9 million bbls. (2.4 million at December 31, 2023) remain in the pipeline or storage tanks, awaiting final sale by Petroperu. During the year, a decrease in future oil prices to the Peru embedded derivative resulted in a net derivative liability. A 1% change to the hedged range price would result in a $1.2 million change to the net derivative liability. The derivative gains/losses are only materialized when oil is effectively sold to third parties at Bayovar.

2) Corporate hedge program to cover a portion of 2024 and 2025 production.

During the year, the Company executed hedging agreements that consisted of multiple trades that totaled 2.6 million barrels of Brent oil with settlements dates from September 2024 to October 2025. The hedge types included put options of $65.00 per barrel, call options of $84.20 and $84.25 per barrel, and call options of $104.25 and $104.50 per barrel. At December 2024, there was a remainder of 1.7 million in hedged barrels of Brent oil that resulted in a net derivative asset of $1.3 million.

Decommissioning liabilities

The undiscounted uninflated value of estimated decommissioning liabilities is $64.4 million ($39.0 million in 2023). The present value of the liabilities was calculated using average risk-free rates between 4.8% to 6.3% (December 31, 2023: 5.3%) to reflect the market assessment of the time value of money as well as risks specific to the liabilities that have not been included in the cash flow estimates. The inflation rate used in determining the cash flow estimate was 2.0%. The revisions to the decommissioning liabilities includes changes to cost estimates, the risk free rates and adjustments for inflation.

In Q4 2024, PetroTal acquired $13.6 million in decommissioning liabilities as part of the Ucawa Energy S.A.C. asset acquisition. The present value of the liability was calculated at December 31, 2024 using average risk free rates between 4.8% to 6.0%. The liability represents the present value of abandonment costs for four wells and one water well to be decommissioned in December 2037.

Balance at January 1, 2023	13,393
Additions	5,390
Revisions to decommissioning liabilities	2,370
Accretion	994
Balance at December 31, 2023	22,147
Additions	3,205
Asset acquisition	13,590
Revisions to decommissioning liabilities	(5,851)
Accretion	1,292
Balance at December 31, 2024	34,383

Short and long-term debt

At December 31, 2024 the Company had short term debt of $10.0 million at an interest rate of 5.99% to be paid in full 120 days from the date of borrowing. The proceeds will be used to fund short term working capital needs. The Company has $67.0 million in remaining available credit. No debt covenants were set forth by the lenders in the loan agreements and all lines of credit are available for one year with the option to renew.

Bank	Agreement Date	Balance	Line of Credit	Interest Rate	Payment Term	Collateral
BCP	March 2023	$10,047	$20,000	5.99 %	120 days	—
BanBif	April 2024	—	$2,000	—	90 days	—
Scotia Bank[(1)]	April 2024	—	$5,000	—	360 days	$5,000
JP Morgan Bank	May 2024	—	$20,000	—	120 days	—
GNB	August 2024	—	$10,000	—	180 days	—
Banco Pichincha	September 2024	—	$20,000	—	120 days	Insurance endorsement
Balance at December 31, 2024		$10,047	$77,000			

[(1)] The Scotia Bank $5.0 million cash collateral requirement was removed on January 23, 2025.

Leases

In prior years, PetroTal commenced a service lease arrangement with a supplier that provides turnkey power generation equipment services. In Q4 2024, the Company signed an addendum to lease additional equipment, which resulted in a $15.0 million present value increase to lease assets and liabilities on the balance sheet. The Company has the option to buy the equipment on June 27, 2031 for $3.0 million. The incremental borrowing rate used to measure the lease liabilities was 8.5%. The lease term ends September 2031.

Also in Q4 2024, PetroTal executed an agreement to acquire a drilling rig from a Houston-based equipment Company. The purchase of the rig was financed through a lease agreement (36 month term) with a Peruvian bank which resulted in a $13.3 million present value increase to lease assets and liabilities on the balance sheet. The Company has the option to buy the rig on October 31, 2028 for $0.1 million. The incremental borrowing rate used to measure the lease liability was 8.5%. The lease term ends December 2027.

The lease liabilities includes three office leases, one in Houston, Texas and two in Lima, Peru. The Houston lease was renewed with a 1.1 million present value increase for a term of 6.0 years with an incremental borrowing rate of 9.5%. The Lima leases are for 3-5 years with an incremental borrowing rate of 8.5% with no changes in present value.

Lease liabilities at January 1, 2023	19,642
Revisions	12,389
Payments	(4,465)
Interest on leases	1,304
Lease liabilities at December 31, 2023	28,870
Additions	28,125
Acquisition	15
Revisions	1,045
Payments	(5,819)
Interest on leases	2,405
Lease liabilities at December 31, 2024	54,641
Represented as:	
Current liability	10,426
Non-current liability	44,215

As of December 31, 2024, total lease liabilities have the following minimum undiscounted payments per year:

Year	
2025	13,119
2026	13,155
Thereafter	40,973
Total	67,247

Share capital

Authorized share capital consists of an unlimited number of common shares without nominal or par value. The holders of common shares have one vote per share and are entitled to receive dividends as recommended by the Board of Directors.

As of March 18, 2025, PetroTal has the following securities outstanding (in thousands):

Common shares	916,623	98%
Performance share units	18,279	2%
Total	934,902	100%

Dividends

During the years ended December 31, 2024 and 2023, the Company paid dividends to shareholders in the amount of $60.5 million and $55.6 million, respectively. The Company declared dividends per share in the amount of $0.02 in Q1 2024, and $0.015 in each of the following quarters through Q4 2024. The Company's sustainable dividend policy is to pay dividends based on current liquidity exceeding $60.0 million.

Normal course issuer bid

On May 16, 2023, the Company announced that the Toronto Stock Exchange approved a notice of intention to commence a normal course issuer bid ("NCIB"). The NCIB allows the Company to purchase up to 44.2 million common shares (representing approximately 5% of outstanding common shares as at May 12, 2023) beginning May 18, 2023 and ending no later than May 17, 2024. Common shares purchased under the NCIB will be cancelled. In May 2024, the Company announced the renewal the NCIB which ends no later than May 23, 2025. This renewal includes the intention to purchase up to 14.6 million common shares (representing approximately 2% of its outstanding common shares at May 10, 2024).

During the years ended December 31, 2024 and 2023, the Company purchased 8.8 million and 11.3 million common shares under the NCIB for total consideration of $4.9 million and $6.5 million, respectively. The surplus between the total consideration and the carrying value of the shares repurchased was recorded against retained earnings.

6.3. NON-GAAP TERMS

This report contains financial terms that are not considered measures under GAAP such as operating netback, operating netback per bbl., revenues and transportation expense adjusted, funds flow provided by operations, funds flow provided by operations per bbl., funds flow netback per bbl., free funds flow and diluted funds flow per share that do not have any standardized meaning under GAAP and may not be comparable to similar measures presented by other companies. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

NON-GAAP FINANCIAL MEASURES

Revenue and transportation expense adjustment

Revenue and transportation expense adjustment are a non-GAAP measure that includes transportation ONP pipeline tariff, marketing fee, barging and diluent expenses. Tariff and marketing fees are expenses usually recorded by reducing revenues in the financial statements.

Funds flow information

Funds flow provided by operations ("FFO"), is a non-GAAP measure that includes all cash generated from operating activities and changes in non-cash working capital. The Company considers funds flow from operations to be a key measure as it demonstrates Company's profitability. A reconciliation from cash provided by operating activities to funds flow provided by operations is as follows:

	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Cash flow from operating activities				
Net income	21,241	21,530	111,450	110,505
Adjustments for:				
Depletion, depreciation and amortization	18,504	12,232	62,242	39,801
Accretion of decommissioning obligation	360	298	1,292	994
Equity based compensation expense	823	1,145	1,528	4,340
Financial interest expense	2,047	2,561	3,577	10,473
Deferred income tax expense	6,473	(3,160)	28,521	25,766
Commodity price unrealized derivatives (gain) loss	(2,725)	11,662	6,683	10,223
Funds flow provided by operations before non-cash working capital	**46,724**	**46,268**	**215,293**	**202,102**
Changes in non-cash working capital:				
Receivables and restricted cash	(14,730)	(15,760)	(13,522)	26,668
Advances and prepaid expenses	(306)	(906)	(9,043)	(746)
Inventory	9,877	2,400	(302)	497
Trade and other payables	13,065	21,876	10,253	9,445
Income tax payable	(6,642)	—	18,586	—
Commodity price realized derivatives gain	—	—	9,645	2,734
Cash (paid) received for income taxes	(150)	(111)	(150)	(1,241)
Net cash provided by operating activities	**47,838**	**53,767**	**230,760**	**239,459**

	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Cash flow from investing activities				
Exploration and evaluation asset additions	(402)	(359)	(1,434)	(1,631)
Property, plant and equipment additions	(50,187)	(31,798)	(161,393)	(106,822)
Asset acquisition	(1,700)	—	(1,700)	—
Non-cash changes in working capital	(8,998)	(1,243)	(1,788)	2,700
Net cash used in investing activities	(61,287)	(33,400)	(166,315)	(105,753)
Net cash (used in) provided by operating and investing activities	(13,449)	20,367	64,445	133,704

CAPITAL MANAGEMENT MEASURES

Adjusted EBITDA

Adjusted EBITDA means earnings before interest, taxes, depreciation and amortization, derivatives, foreign exchange, adjusted for realized derivatives gain (loss) and share based compensation.

	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Net income	21,241	21,530	111,450	110,505
Adjustments to reconcile net income:				
Depletion, depreciation and amortization	18,504	11,527	62,242	39,801
Financial expense	2,096	3,150	3,156	15,341
Income tax expense	(209)	4,076	39,902	33,002
Commodity price derivatives loss (gain)	(2,726)	11,662	10,424	12,479
Foreign exchange loss (gain)	448	(1,163)	743	(323)
EBITDA (non-GAAP)	39,355	50,782	227,917	210,805
Commodity price derivatives realized (loss) gain	—	—	5,904	478
Share based compensation	812	1,142	3,151	4,363
Adjusted EBITDA (non-GAAP)	40,167	51,924	236,972	215,646
Capital expenditures	(50,589)	(32,157)	(162,827)	(108,454)
Free funds flow (non-GAAP)	(10,422)	19,767	74,145	107,192

Note: The EBITDA and Adjusted EBITDA calculation methodology was changed in Q2 2024 and for prior periods to exclude realized derivatives gain (loss) and include adjustments for foreign exchange and share based compensation to better measure the Company's generated cash.
EBITDA: For the three months ended December 31, 2023, previously reported was $51,946 (year ended 2023 was $211,128) as the amount previously reported did not include foreign exchange gain. Adjusted EBITDA: For the three months ended December 31, 2023 previously reported was $40,284 (year ended 2023 was $199,127) as the amount previously reported included realized derivatives gain (loss) and did not include share based compensation.

Free funds flow after investing activities is a non-GAAP measure and the Company considers free funds flow or free cash flow to be a key measure as it demonstrates the Company's ability to fund a return of capital without accessing outside funds.

Operating netback

The Company considers operating netbacks to be a key measure that demonstrates the Company's profitability relative to current commodity prices. Netback is calculated by dividing net operating income by total revenue.

7. 2024 RESERVE REPORT

The summary below sets forth PetroTal's reserves at December 31, 2024, for Bretana and Los Angeles oil fields, as presented by NSAI, a qualified independent reserves evaluator. The figures in the following tables have been prepared in accordance with the standards contained in the most recent publication of the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and the reserve definitions contained in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") of the Canadian Securities Administrators. More detailed information will be included in PetroTal's AIF for the year ended December 31, 2024 to be posted on SEDAR (www.sedarplus.ca) and on PetroTal's website.

Block 95 - Bretana heavy oil field

Oil production commenced in Bretana in June 2018 via a long-term testing program of the single oil producer. In May 2019, the Company received the approval of the Environmental Impact Assessment ("EIA") to fully develop the Bretana field in Block 95. This approval provided PetroTal with the necessary permits to execute its development strategy at Bretana.

Block 131 - Los Angeles light oil field

The Los Angeles oil field at Block 131 was discovered by Ucawa (formerly CEPSA Peru S.A.C.) in 2013. As of September 30, 2024 the field has produced a total of approximately 7.8 million bbls. Block 131 is held under an exploration and production license agreement expiring in 2038, subject to a 23.48% royalty rate at field production levels under 5,000 bopd., with a similar scaling factor to Block 95 above 5,000 bopd. All produced oil is currently sold to Petroperu, Peru's state-owned oil Company, at Pucallpa. The oil is then transported by barge along the Ucayali River (passing PetroTal's Bretana oil field) to the Iquitos refinery.

Summary of Oil Reserves and Net Present Values as of December 31, 2024

Company Oil Reserves (bbls. in millions)	Heavy Oil		Light Oil		Future Net Revenue After Income Taxes Discounted at (in USD billion)				
	Gross	Net	Gross	Net	0%	5%	10%	15%	20%
Proved Developed Producing	44.7	44.7	0.8	0.8	$1.2	$0.9	$0.8	$0.7	$0.6
Proved Undeveloped	18.2	18.2	3.4	3.4	$0.6	$0.5	$0.4	$0.3	$0.2
Total Proved	62.9	62.9	4.2	4.2	$1.8	$1.4	$1.2	$1.0	$0.8
Probable	45.0	45.0	1.6	1.6	$1.5	$0.9	$0.6	$0.4	$0.3
Total Proved & Probable	107.9	107.9	5.8	5.8	$3.3	$2.3	$1.8	$1.4	$1.1
Possible	98.7	98.7	0.9	0.9	$4.0	$1.9	$1.0	$0.6	$0.4
Total Proved & Probable & Possible	206.6	206.6	6.7	6.7	$7.3	$4.2	$2.8	$2.0	$1.5

Summary of Pricing and Inflation Rate Assumptions - Forecast Prices and Costs (US$/bbl.)

Year-end Forecast	2025	2026	2027	2028	2029	2030
Brent December 31,	$75.58	$78.51	$79.89	$81.82	$83.46	$85.13
Brent January 1, 2025 (Heavy Oil)	$66.15	$69.01	$70.30	$72.17	$73.88	$75.44
Brent January 1, 2025 (Light Crude)	$80.98	$83.91	$85.29	$87.22	$88.86	$90.53

Year-end Crude Oil Reserves (bbls. in millions)

Category	2024	2023	Change
Proved Developed Producing	45.5	28.5	59.6%
Proved Undeveloped	21.6	19.5	10.8%
Total Proved	67.1	48.0	39.8%
Probable	46.6	52.2	(10.7%)
Total Proved plus Probable	113.7	100.2	13.5%
Possible	99.6	99.4	0.2%
Total Proved plus Probable & Possible	213.3	199.6	6.9%

Year-end Net Present Value at 10% - After Income Tax ($ millions)

Category	2024	2023	Change
Proved Developed Producing	$776	$487	59.3%
Proved Undeveloped	$353	$401	(12.0%)
Total Proved	$1,129	$888	27.1%
Probable	$592	$751	(21.2%)
Total Proved plus Probable	$1,721	$1,639	5.0%
Possible	$1,036	$869	19.2%
Total Proved plus Probable & Possible	$2,757	$2,508	9.9%

Year-end Net Asset Value ("NAV") per Share - After Tax

	December 31, 2024		December 31, 2023	
Category	US$/sh	CAD$/sh	US$/sh	CAD$/sh
Proved	$1.89	$2.74	$0.97	$1.29
Proved plus Probable	$2.91	$4.21	$1.80	$2.39
Proved plus Probable & Possible	$4.67	$6.76	$2.75	$3.65

Reserve Life Index ("RLI")

Category	December 31, 2024
Proved	10.3 years
Proved plus Probable	17.5 years
Proved plus Probable & Possible	32.8 years

Future Development Costs

The following information sets forth development costs deducted in the estimation of PetroTal's future net revenue attributable to the reserve categories noted below:

Proved	$192 million
Proved plus Probable	$645 million
Proved plus Probable & Possible	$932 million

The future development costs are estimates of capital expenditures required in the future for PetroTal to convert the corresponding reserves to proved developed producing reserves. Future abandonment cost estimates are $68 million (1P), $81 million (2P), and $113 million (3P).

Bretana's reserve life index for 1P and 2P reserves is 10.3 years and 17.5 years, respectively. The cumulative capital invested combined with all future development and abandonment costs represents total finding and development costs of $12.06/bbl. for 1P reserves, $10.64/bbl. for 2P reserves and $6.23/bbl. for 3P reserves.

Original Oil in Place ("OOIP") remains relatively flat from 2022 levels. Now at 411, 528, and 702 million bbls. (including Los Angeles) for the 1P, 2P and 3P cases, respectively.

In addition to ongoing development of the Bretana oilfield, there are other prospects and exploration opportunities.

8. SIGNIFICANT JUDGEMENTS AND ESTIMATES

Management is required to make judgments, assumptions and estimates that have a significant impact on the Company's financial results. Significant judgments in the Financial Statements include going concern, financing arrangements, impairment indicators, assessment of transfers from Exploration and Evaluation ("E&E") to Property, Plant and Equipment ("PP&E"), leases, derivatives, asset acquisition and joint arrangements. Significant estimates in the Financial Statements include commitments, provision for future decommissioning obligations, recoverable amounts for exploration and evaluation assets and accruals. In addition, the Company uses estimates for numerous variables in the assessment of its assets for impairment purposes, including oil prices, exchange rates, discount rates, cost estimates and production profiles. By their nature, all of these estimates are subject to measurement uncertainty, may be beyond management's control, and the effect on future Financial Statements from changes in such estimates could be significant.

Critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements along with additional information about such judgements and estimates are included in the Consolidated Financial Statements and the accompanying notes as of December 31, 2024 and 2023.

USES OF CRITICAL ACCOUNTING ASSUMPTIONS, ESTIMATES AND JUDGEMENTS

The Company's critical estimates and associated assumptions are based on historical experience and other factors that are considered relevant. Such estimates and assumptions affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from estimates.

The critical estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the same period if the revision affects only that period or in the period of the revision and future periods if the revision affects current and future periods.

Critical estimates and judgements in applying accounting policies that have the most significant effect on the amounts recognized in the Financial Statements are summarized below:

Functional Currency

The functional currency of each of the Company's entities is the United States dollar, which is the currency of the primary economic environment in which the entities operate.

Exploration and Evaluation Assets

The accounting for E&E assets requires management to make certain estimates and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbons, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalized as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of "sufficient progress" is an area of judgement, and it is possible to have exploratory costs remain capitalized for several years while additional drilling is performed, or the Company seeks government, regulatory or partner approval of development plans.

Petroleum and natural gas assets are grouped into cash generating units ("CGUs") identified as having largely independent cash flows and are geographically integrated. The determination of the CGUs was based on management's interpretation and judgement.

Decommissioning Obligations

Decommissioning obligations will be incurred by the Company at the end of the operating life of wells or supporting infrastructure. The ultimate asset decommissioning costs and timing are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques, and experience at other production sites. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The expected amount of expenditure is estimated using a discounted cash flow calculation with a risk-free discount rate. Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed, and the associated costs can be estimated.

Erosion Costs

Erosion control costs are expenses incurred by the Company to protect the producing fields and nearby community from erosion cause by the river. These costs will be capitalized and/or expensed depending on the nature of the outflow and the direct benefits received by the Company or the community. Erosion costs are presented in a separate expense line in the Statement of Earnings and Other Comprehensive Income, recognized as incurred and for a better reliable measurement. The financial statement notes presents the nature, measurement basis, and transparency of this new activity.

Deferred Tax Assets & Liabilities

The estimation of income taxes includes evaluating the recoverability of deferred tax assets based on an assessment of the Company's ability to utilize the underlying future tax deductions against future taxable income prior to the expiration of those deductions. Management assesses whether it is probable that some or all of the deferred income tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income, which in turn is dependent upon the successful discovery, extraction, development and commercialization of oil and gas reserves. To the extent that management's assessment of the Company's ability to utilize future tax deductions changes, the Company would be required to recognize more or fewer deferred tax assets, and future income tax provisions or recoveries could be affected. The measurement of deferred income tax provision is subject to uncertainty associated with the timing of future events and changes in legislation, tax rates and interpretations by tax authorities.

Provisions, Commitments and Contingent Liabilities

Amounts recorded as provisions and amounts disclosed as commitments and contingent liabilities are estimated based on the terms of the related contracts and management's best knowledge at the time of issuing the Financial Statements. The actual results ultimately may differ from those estimates as future confirming events occur.

The Company has one reportable business segment which did not have any critical accounting estimate changes during the past two financial years.

Business Combinations

The Company adopted the amendments to IFRS 3 – Business Combinations. Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the acquired assets constitute a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination are measured at their fair values. If applicable, the excess or deficiency of the fair value of net assets acquired compared to consideration paid is recognized as a gain on business combination or as goodwill on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period incurred. As part of the assessment to determine if the acquisition constitutes a business, the Company may elect to apply the concentration test on a transaction by transaction basis. The test is met if substantially all of the fair value related to the gross assets acquired is concentrated in a single identifiable asset (or group of similar assets) resulting in the acquisition not being deemed a business and recorded as an asset acquisition. The amendments introduced an optional concentration test, narrowed the definitions of a business and outputs, and clarified that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs.

9. NEW ACCOUNTING STANDARDS ISSUED BUT NOT EFFECTIVE

New accounting standards and interpretations were issued and are mandatory for future accounting periods. With respect to IFRS 18 (Presentation and Disclosure in Financial Statements) issued by the IASB in April 2024, the Company is currently evaluating the impact on the Company's Financial Statements. Retrospective application of the standard is mandatory for annual reporting periods starting from January 1, 2027 onwards with earlier application permitted.

10. RELATED PARTY TRANSACTIONS

The Company had no related party transactions or off-balance sheet arrangements. The Company's key management includes the Directors and Officers. The summary of benefits paid or accrued to executives and directors is:

	Year Ended December 31	
	2024	2023
Salaries, incentives and short term benefits	2,021	1,846
Director's fees	1,322	1,014
Share-based compensation	1,736	2,430
Total	5,079	5,290

The compensation, share-based awards, and non-equity incentive, paid or accrued to the Chief Executive Officer and Board of Directors members are as follows:

Name	Compensation Earned	Share-based awards	Non-Equity Incentive Plans	2024 Total	2023 Total
Manuel Pablo Zuniga-Pflucker(1)	520,000	1,272,000	261,945	2,053,945	1,887,500
Mark McComiskey (Chair)	105,000	183,352	—	288,352	287,733
Gavin Wilson	75,000	101,979	—	176,979	121,671
Eleanor J. Barker	97,000	101,429	—	198,429	143,158
Roger M. Tucker(2)	57,651	61,419	—	119,070	141,158
Jon Harris	83,174	100,455	—	183,629	120,250
Felipe Arbelaez	80,000	100,227	—	180,227	58,109
Emily Morris	75,000	100,165	—	175,165	26,460
Luis Carranza(3)	—	—	—	—	115,034
Director Compensation	1,092,825	2,021,026	261,945	3,375,796	2,901,073

(1) Mr. Zuniga-Pflucker does not receive compensation fees or share-based awards for his role as a Director.
(2) Director retired from the Board in August 2024.
(3) Director retired from the Board in June 2023.

11. TAXES

The Company's effective tax rate is impacted by the relative pre-tax income earned by the Company's operations in Canada, U.S., and Peru. The Company is subject to statutory tax rates of 23% in Canada, 21% in the U.S. and 32% in Peru (activities of the Company in Peru are subject to a 30% statutory tax rate plus 2% in accordance with Law 27343). The Company files federal income tax returns and local income tax returns in the various jurisdictions.

The tax at the effective rate differed from the tax at the statutory rate as follows:

	Year Ended	
	December 31 2024	December 31 2023
Earnings before income taxes	151,352	143,507
Canadian corporate tax rate	23%	23%
Expected income tax expense	34,811	33,007
Increase (decrease) in taxes resulting from:		
Non-deductible expenses and other	(1,349)	1,408
Tax differential on foreign jurisdictions	6,440	10,212
Change in valuation allowance	—	(11,625)
Provision for income taxes	**39,902**	**33,002**

The deferred income tax balances are as follows:

	Year Ended	
	December 31 2024	December 31 2023
Deferred income tax asset:		
Property, plant, and equipment	—	7
Net operating loss carryover	1,013	4,119
Other tax pools	950	8,919
Deferred income tax asset	**1,963**	**13,045**
Deferred income tax liability:		
Property, plant, and equipment	(81,082)	(58,554)
Derivative assets and liabilities	3,271	(2,372)
Preoperative expenses	1,912	2,549
Net operating loss carryover	41	2,156
Other tax pools	3,310	1,112
Deferred income tax liability	**(72,548)**	**(55,109)**

The Company recognized the net tax amount related to Net Operating Losses ("NOLs") and deferred tax liabilities in Canada, Peru and the US. As of December 31, 2024, the Company consumed all losses in Canada (December 31, 2023: $21 million) and all losses in Peru related to Bretana (December 31, 2023: $7 million). The US has $4 million tax losses remaining (December 31, 2023: $1 million). The US non-capital losses can be carried forward indefinitely.

Ucawa has $82 million in tax losses at the end of December 31, 2024 but no related deferred tax asset has been recognized. These losses are being carried forward and are available to offset against future tax gains.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as of December 31, 2024 is approximately $22 million (December 31, 2023: $29 million).

12. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

GUARANTEES AND COMMITMENTS

As at December 31, 2024, the Company holds the following letters of credit guaranteeing its commitments in exploration block 107:

Block	Beneficiary	Amount	Commitment	Expiration
107	Perupetro	$1,500	1st exploration well, minimum work 5th exploratory period	May 2026
107	Perupetro	$1,500	2nd exploration well, minimum work 5th exploratory period	May 2026
		$3,000		

PetroTal also signed two Technical Evaluation Agreements ("TEA") with Perupetro in December 2024. The TEA's for Blocks 97 and 98 are located in the vicinity and on trend with PetroTal's Block 131, as well as the Aguaytia and Agua Caliente fields in Peru's Ucayali Basin. Contractual commitments will be executed in two 12-month phases, and mainly include geological and geophysical studies such as seismic imaging, geochemical modeling and hydrocarbon potential evaluation reports.

The Company progressed its preventive riverbank erosion control program aimed to protect the Bretana field and nearby community. The estimated total project cost has a range of $65 million to $75 million, which will be allocated approximately 65% to operating expense and 35% to capital expenditures during the next years. This program represents a significant operational and environmental commitment, and indicates a proactive approach to environmental stewardship for a permanent solution for the riverbank erosion.

As part of Ucawa Energy S.A.C. asset acquisition, a tax administrative and a judicial legal case were considered as possible, with a total legal contingency of approximately $2.5 million. According to clause 12.5 in the Purchase Agreement, the seller (CEPSA S.A.) is obligated to indemnify PetroTal of any legal action, and/or fines if applicable.

CONTRACTUAL OBLIGATIONS

Refer to "Short and long-term debt" in section "6.2 Balance Sheet Information" for material changes to the Company's contractual obligations.

13. FORWARD-LOOKING STATEMENTS AND BUSINESS RISKS

FOREIGN EXCHANGE RATE RISK

The Company's functional currency is the United States dollar. Foreign exchange gains or losses can occur on translation of working capital denominated in currencies other than the functional currency of the jurisdiction which holds the working capital item. Excluding the impact of changes in the cross-rates, a 1% fluctuation in translation rates would have nil impact on net income or loss, based on foreign currency balances held at December 31, 2024.

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Liquidity is managed through short and long-term cash, debt and equity management strategies. The Company's liquidity risk is impacted by current and future commodity prices. If required, the Company will also consider additional short-term financing or issuing equity in order to meet its future liabilities. Declines in future commodity prices could affect the Company's ability to fund ongoing operations. The current economic environment may have a significant impact on the Company including, but not exclusively:

- material declines in revenue and cash flows as a result of the decline in commodity prices;
- declines in revenue and operating activities due to reduced capital programs and the shut-in of production;
- inability to access financing sources;
- increased risk of non-performance by the Company's customers and suppliers;
- interruptions in operations as the Company adjusts personnel to the dynamic environment; and,
- delivery and transportation of oil at the Bayovar port and sale swap price risk.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgments made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

CREDIT RISK

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss to the Company. The Company's VAT is primarily for sales tax credits on exploration and drilling expenses incurred in prior years. These credits will be applied to future oil development activities or recovered as per the sales tax recovery legislation currently in effect. The majority of the Company's trade receivable balance relates to oil sales and purchase price adjustments to two customers, being Petroperu, a state-owned company and Novum, an oil trading company. The Company has a long-term sales agreement for oil exports through Brazil, whereby sales are FOB Bretana. Sales through the ONP pipeline are due and payable 240 days after the final delivery of the oil to the Bayovar terminal. During the year ended December 31, 2024, 88.4% of oil sales were to Novum (Brazil export route), 11.3% were to Petroperu (Iquitos refinery), and 0.3% from Ucawa. The Company has not experienced any material credit losses in the collection of its trade receivables.

Impairment to a financial asset is only recorded when there is objective evidence of impairment and the loss event has an impact on future cash flow and can be reliably estimated. Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. Management believes that there is no risk on the recoverability and/or applicability of the sales tax credits. Therefore, no impairment to the carrying value of these assets has been estimated. The Company has deposited its cash and cash equivalents with reputable financial institutions, with which management believes the risk of loss to be remote. The maximum credit exposure associated with financial assets is their carrying value. At December 31, 2024, the cash and cash equivalents were held with six different institutions from three countries, mitigating the credit risk of a collapse of one particular bank.

Additional information regarding risk factors including, but not limited to, risks related to political developments in Peru and environmental risks is available in the Company's AIF, a copy of which may be accessed through the SEDAR+ website (www.sedarplus.ca).

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A may constitute forward-looking statements. These statements relate to future events or the Company's future performance, including, but not limited to: PetroTal's business strategy, objectives, strength, focus and outlook, drilling, completions, workovers and other activities including expanding infrastructure and exploring undeveloped acreage and the anticipated costs and results of such activities, environmental remediation and social initiatives, the ability of the Company to achieve drilling success consistent with management's expectations, anticipated future production and revenue, oil production levels, the 2025 capital program and budget, including drilling plans, balance sheet strength, hedging program and the terms thereof, and future development and growth prospects. All statements other than statements of historical fact may be forward-looking statements. In addition, statements relating to expected production, reserves, prospective resources, recovery, costs and valuation are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Forward-looking statements are often, but not always, identified by the use of words such as “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “predict”, “potential”, “intend”, “could”, “might”, “should”, “believe” and similar expressions.

The forward-looking statements are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the ability of existing infrastructure to deliver production and the anticipated capital expenditures associated therewith, reservoir characteristics, recovery factor, exploration upside, prevailing commodity prices and the actual prices received for PetroTal's products, including pursuant to hedging arrangements, the availability and performance of drilling rigs, facilities, pipelines, other oilfield services and skilled labor, royalty regimes and exchange rates, the application of regulatory and licensing requirements, the accuracy of PetroTal's geological interpretation of its drilling and land opportunities, current legislation, receipt of required regulatory approval, the success of future drilling and development activities, the performance of new wells, the Company's growth strategy, general economic conditions and availability of required equipment and services. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon by investors. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of reserve estimates, the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price volatility, price differentials and the actual prices received for products, exchange rate fluctuations, legal, political and economic instability in Peru, access to transportation routes and markets for the Company's production, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Please refer to the risk factors identified in the AIF which is available on SEDAR+ at www.sedarplus.ca.

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company cannot guarantee future results, levels of activity, performance, or achievements. The risks and other factors, some of which are beyond the Company’s control, could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A.

The forward-looking statements contained in this MD&A are expressly qualified by the foregoing cautionary statement. Subject to applicable securities laws, the Company is under no duty to update any of the forward-looking statements after the date hereof or to compare such statements to actual results or changes in the Company's expectations. Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information should not be used for purposes other than for which it is disclosed herein.

Prospective resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Estimates of prospective resources included in this document relating to the Osheki prospect are based upon an independent assessment completed by NSAI with an effective date of September 30, 2018 and prepared in accordance with COGE and the standards established by NI 51-101. For additional information about the Company's prospective resources, see the Company's website for the most current press release.

ADDITIONAL INFORMATION

Additional information about PetroTal Corp. and its business activities, including PetroTal's audited Financial Statements for the years ended December 31, 2024 and 2023 are available on the Company's website at www.petrotal-corp.com, and at www.sedarplus.ca.

DIRECTORS
Mark McComiskey (1)(4)(5)
Chair of the Board

Felipe Arbelaez (3)(4)

Eleanor Barker (4)(5)

Jon Harris (1)(2)(5)

Emily Morris(5)

Gavin Wilson (1)(2)(3)

Manuel Pablo Zuniga-Pflucker (2)

OFFICERS AND SENIOR EXECUTIVES
Manuel Pablo Zuniga-Pflucker
President and Chief Executive Officer

Camilo McAllister
Executive VP and Chief Financial Officer

Jose Contreras
Chief Operating Officer

Sudan Maccio
Chief Legal Counsel and Corporate Secretary

Glen Priestley
VP Finance and Treasurer

Emilio Acin-Daneri
VP Business Development

Max Torres
VP Exploration

Guillermo Florez
General Manager Peru

CORPORATE HEADQUARTERS
PetroTal Corp.
16200 Park Row, Suite 300
Houston, Texas 77084
Office: 713.609.9101
info@petrotal-corp.com
www.petrotal-corp.com

REGISTERED OFFICE
PetroTal Corp.
4200 Bankers Hall West, 888-3rd Street
Calgary, Alberta, Canada

OPERATING OFFICE
PetroTal Peru SRL
144 Dionisio Derteano, Suite 1200
San Isidro
Lima, Peru

STOCK EXCHANGES
TSX Exchange
Toronto, Ontario, Canada
TSX: TAL

AIM Stock Exchange
London, United Kingdom
AIM: PTAL

OTCQX Stock Exchange
New York, USA
OTCQX: PTALF

LEGAL COUNSEL
Stikeman Elliott LLP
Calgary, Alberta, Canada

AUDITORS
Deloitte LLP
Calgary, Alberta, Canada

NOMINATED & FINANCIAL ADVISER
Strand Hanson Limited
London, United Kingdom

JOINT BROKERS
Stifel Nicolaus Europe Limited
London, United Kingdom

Peel Hunt LLP
London, United Kingdom

RESERVES EVALUATORS
Netherland, Sewell & Associates, Inc.
Dallas, Texas, USA

TRANSFER AGENT AND REGISTRAR
Computershare Trust Company of Canada
Calgary, Alberta, Canada
London, United Kingdom
Massachusetts, USA and New Jersey, USA

(1) Member of the Corporate Governance and Compensation Committee.
(2) Member of the Reserves Committee.
(3) Member of the HSE CSR Committee.
(4) Member of the Audit Committee.
(5) Member of the Technical Committee.

GLOSSARY / ABBREVIATIONS

1P	Proved
2P	Proved plus Probable
3P	Proved plus Probable and Possible
AIF	Annual Information Form
bbl(s)	Barrel(s)
bopd	Barrels of Oil per Day
Capex	Capital Expenditures
CGUs	Cash Generating Units
COGE	Canadian Oil and Gas Evaluation Handbook
CSR	Community, Social and Regulatory
DD&A	Depletion, Depreciation and Amortization
E&E	Exploration and Evaluation
EIA	Environmental Impact Assessment
ESG	Environmental and Social Governance
FOB	Freight on board
FFO	Funds Flow Provided by Operations
G&A	General and Administrative
GAAP	Generally Accepted Accounting Principles
IFRS®	International Financial Reporting Standards (“IFRS®” or "IFRS® Accounting Standards") as issued by the International Accounting Standards Board (“IASB”)
MD&A	Management's Discussion and Analysis
mmboe	Million Barrels of Oil Equivalent
NAV	Net Asset Value
NCIB	Normal Course Issuer Bid
Netback	Benchmark to assess the profitability based on revenues less royalties, operating and transportation costs
NI 51-101	National Instruments - Standards of Disclosure for Oil and Gas Activities
NOI	Net Operating Income
NPV	Net Present Value
NSAI	Netherland Sewell and Associates, Inc.
OCP	Ecuador Pipeline
ONP	Northern Peruvian Pipeline
OOIP	Original Oil in Place
PP&E	Property, Plant and Equipment
RLI	Reserve Life Index
SDGs	Sustainable Development Goals
USD	United States Dollar ($)
VAT	Value Added Tax
VS1	Upper Vivian Sand