ANNUAL REPORT

AS AT AND FOR THE YEAR ENDED

DECEMBER 31, 2025

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FINANCIAL AND OPERATIONAL HIGHLIGHTS	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
FINANCIAL						
Petroleum and natural gas sales	**143,789**	125,064	15	**513,085**	468,432	10
Cash provided by operating activities	**62,804**	48,067	31	**264,256**	209,145	26
Adjusted funds from operations [(1)]	**76,817**	69,406	11	**261,525**	221,978	18
Basic ($/common share) [(1)]	**0.39**	0.35	11	**1.32**	1.13	17
Diluted ($/common share) [(1)]	**0.38**	0.35	9	**1.29**	1.11	16
Net income and comprehensive income	**19,064**	13,800	38	**63,058**	45,423	39
Basic ($/common share)	**0.10**	0.07	43	**0.32**	0.23	39
Diluted ($/common share)	**0.09**	0.07	29	**0.31**	0.23	35
Capital expenditures, net of A&D [(1)]	**42,806**	97,046	-56	**328,305**	333,147	-1
Total assets	**1,600,515**	1,450,679	10	**1,600,515**	1,450,679	10
Bank debt	**179,861**	108,993	65	**179,861**	108,993	65
Net debt [(1)]	**189,703**	124,883	52	**189,703**	124,883	52
Shareholders' equity	**1,139,639**	1,063,004	7	**1,139,639**	1,063,004	7
Return on average capital employed (%) [(1)(3)]				**8**	6	33
Weighted average shares outstanding (000s)						
Basic	**199,516**	196,557	2	**198,838**	195,719	2
Diluted	**203,089**	200,801	1	**202,105**	199,631	1
OPERATIONS						
Average daily production						
Oil (bbls/d)	**11,024**	9,297	19	**9,316**	8,623	8
NGLs (bbls/d)	**5,790**	5,052	15	**5,545**	3,675	51
Gas (mcf/d)	**169,725**	132,608	28	**153,214**	124,902	23
Combined (BOE/d)	**45,102**	36,450	24	**40,397**	33,115	22
Production per million common shares (BOE/d) [(1)]	**226**	185	22	**203**	169	20
Net realized prices, before derivative financial instruments [(1)]						
Oil ($/bbl)	**74.29**	92.53	-20	**83.29**	94.46	-12
NGLs ($/bbl)	**32.49**	38.50	-16	**35.94**	47.56	-24
Gas ($/mcf)	**2.96**	2.02	47	**2.50**	1.97	27
Operating netbacks ($/BOE) [(1)]						
Petroleum and natural gas sales	**34.66**	37.30	-7	**34.80**	38.66	-10
Cost of purchases	**(1.19)**	(0.99)	20	**(1.17)**	(1.35)	-13
Net realized price, before derivative financial instruments [(1)]	**33.47**	36.31	-8	**33.63**	37.31	-10
Realized gain on derivative financial instruments	**1.80**	0.70	157	**1.88**	0.35	437
Net realized price, after derivative financial instruments [(1)]	**35.27**	37.01	-5	**35.51**	37.66	-6
Royalties	**(2.69)**	(2.85)	-6	**(3.13)**	(4.52)	-31
Production expense	**(9.30)**	(8.72)	7	**(9.52)**	(10.01)	-5
Transportation expense	**(3.24)**	(3.64)	-11	**(3.43)**	(3.52)	-3
Operating netback [(1)]	**20.04**	21.80	-8	**19.43**	19.61	-1
Land holdings						
Gross acres	**800,361**	790,918	1	**800,361**	790,918	1
Net acres	**599,740**	588,527	2	**599,740**	588,527	2
Reserves – proved plus probable						
Crude oil and liquids (Mbbls) [(2)]	**175,447**	173,779	1	**175,447**	173,779	1
Gas (MMcf)	**1,637,146**	1,568,229	4	**1,637,146**	1,568,229	4
Combined (MBOE) [(4)]	**448,304**	435,151	3	**448,304**	435,151	3

(1) Refer to advisories regarding non-GAAP and other financial measures.

(2) The three year average ROACE at December 31, 2025 was 9%. Refer to additional information under “Non-GAAP and Other Financial Measures”.

MESSAGE TO SHAREHOLDERS

Kelt Exploration Ltd. ("Kelt" or the "Company") reports its financial and operating results to shareholders for the fourth quarter ended December 31, 2025.

Average production for the three months ended December 31, 2025 was 45,102 BOE per day, up 24% compared to average production of 36,450 BOE per day during the fourth quarter of 2024. Production for the three months ended December 31, 2025 was weighted 37% to oil and NGLs and 63% to gas. During 2025, the Company had a significant amount of production shut-in due to construction delays of a third-party gas plant in its Wembley/Pipestone core area. Despite the shut-ins, Kelt was able to increase average production in 2025 by 22% from 33,115 BOE per day in 2024 to average production of 40,397 BOE per day in 2025. Kelt is forecasting average production in the 46,000 to 47,000 BOE per day range for the first quarter of 2026.

Petroleum and natural gas sales during the fourth quarter of 2025 increased by 15% to $143.8 million, up from $125.1 million in the same period of the previous year. Petroleum and natural gas sales for the year were $513.1 million, up 10% from $468.4 million in 2024. Kelt's net realized average oil price during the fourth quarter of 2025 was $74.29 per barrel, down 20% from $92.53 per barrel in the fourth quarter of 2024. The Company's net realized average NGLs price during the fourth quarter of 2025 was $32.49 per barrel, down 16% from $38.50 per barrel in the fourth quarter of 2024. Kelt's net realized average gas price for the fourth quarter of 2025 was $2.96 per Mcf, up 47% from $2.02 per Mcf in the fourth quarter of 2024.

For the three months ended December 31, 2025, adjusted funds from operations was $76.8 million ($0.38 per share, diluted), up 11% when compared to $69.4 million ($0.35 per share, diluted) in the fourth quarter of 2024. Year over year, adjusted funds from operations increased by 18% to $261.5 million ($1.29 per share, diluted) from $222.0 million ($1.11 per share, diluted) in 2024. During 2025, Kelt recorded net income of $63.1 million ($0.31 per share, diluted) compared to $45.4 million ($0.23 per share, diluted) in the previous year.

Kelt continues to maintain a strong financial position. At December 31, 2025, Kelt had net debt of $189.7 million which equates to 0.7 times 2025 adjusted funds from operations of $261.5 million or 0.5 times forecasted 2026 adjusted funds from operations of $375.0 million.

Capital expenditures incurred during the three months ended December 31, 2025 were $42.8 million, down 56% compared to net capital expenditures of $97.0 million during the fourth quarter of 2024. During the fourth quarter of 2025, the Company spent $22.4 million on drill and complete operations; and $20.4 million on well equipment, facilities and pipelines.

OPERATIONS UPDATE

Kelt's planned 2026 capital expenditure program remains unchanged at $355.0 million. Kelt's previous guidance for 2026 production to average between 50,000 and 52,000 BOE per day also remains unchanged.

- At Wembley/Pipestone, Kelt expects to drill 16 Montney wells and complete 17 wells during the year. These wells will be completed with the higher intensity fracs that the Company tested at its 6-9 pad in 2025. Initial production results from the wells off the 6-9 pad are encouraging and Kelt expects to see demonstrated improvements in EURs and oil-gas ratios resulting from these design changes, based on production results from the 2026 Wembley development program.
- At Wembley/Pipestone, to date in 2026, the Company has drilled a 4-well Montney pad (11-34 surface) and another four wells off the 6-9 pad. Drilling operations have also commenced at the next 4-well pad (16-26 surface). These 12 wells are expected to be completed and brought on production by the end of the second quarter of 2026.
- At Pouce Coupe West, Kelt has drilled and completed two Montney wells that have now commenced production.
- At Oak, the Company completed a 3-D seismic shoot covering approximately 110 sections of land. Kelt has already started to reap the benefits of this seismic shoot where drilling times on its longer horizontal laterals have been reduced by staying in zone for the entire length of the well, as per plan.
- Kelt has added additional water handling facilities at its properties including water disposal wells and water storage

pits which will provide improvements in capital efficiency going forward.

With the start-up of new wells in its Wembley/Pipestone Division where Kelt added additional gas processing capacity at third-party facilities, the Company expects to ramp up production significantly leading into the third quarter of 2026.

Kelt has increased its guidance for adjusted funds from operations for 2026 by $20.0 million from $355.0 million ($1.73 per share, diluted) to $375.0 million ($1.83 per share, diluted). The Company increased its forecast for WTI oil to average US$69.40/bbl (CA$94.66/bbl), up 18% from its previous estimate of US$59.00/bbl (CA$81.27/bbl). At the same time, Kelt reduced its forecast for AECO gas to average CA$2.33/GJ, down 17% from its previous forecast of CA$2.80/GJ.

Management looks forward to updating shareholders with 2026 first quarter results on or about May 7, 2026.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
March 11, 2026

MANAGEMENT'S DISCUSSION & ANALYSIS

Kelt Exploration Ltd. ("Kelt" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources in Western Canada. Kelt's business plan is for long-term profitable growth by implementing a full cycle exploration and development program, with emphasis on low-cost land accumulation with the potential for high rates of return on capital invested. Kelt has an active exploration and development drilling program that it may complement with acquisitions and dispositions that optimize its asset base.

The Company was incorporated under the *Business Corporations Act* (Alberta) on October 11, 2012. Kelt's assets are comprised of three core operating divisions, namely: (1) Wembley/Pipestone in Alberta; (2) Pouce Coupe/Progress/Spirit River in Alberta; and (3) Oak/Flatrock in British Columbia. The Company's British Columbia assets are operated by Kelt Exploration (LNG) Ltd. ("Kelt LNG"), a wholly owned subsidiary of Kelt. The head office of the Company is located at Suite 300, 311 - 6th Avenue S.W., Calgary, Alberta T2P 3H2. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL". Additional information relating to Kelt can be found on SEDAR+ at www.sedarplus.ca.

This Management's Discussion and Analysis ("MD&A") is dated March 11, 2026 and should be read in conjunction with the Company's consolidated financial statements and related notes as at and for the year ended December 31, 2025. The accompanying financial statements have been prepared in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). The Company's Board of Directors approved and authorized the consolidated financial statements on March 11, 2026.

GENERAL ADVISORY

This MD&A contains certain specified financial measures consisting of non-GAAP measures, capital management measures, and supplementary financial measures. These non-GAAP and other financial measures include "funds from operations", "adjusted funds from operations", "adjusted funds from operations per common share", "petroleum and natural gas sales after cost of purchases", "operating income", "operating netback", "capital expenditures, before A&D", "capital expenditures, net of A&D", "net debt", "net realized prices", "combined net realized prices", and "net debt to adjusted funds from operations ratio" which do not have standardized meanings prescribed by generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information and reconciliation to Canadian generally accepted accounting principles "GAAP" measures, see "*Non-GAAP and Other Financial Measures*" in this MD&A.

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. The use of and of the words "will", "expects", "believe", "plans", potential", "forecasts" and similar expressions are intended to identify forward-looking statements. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, including the assumptions underlying such forward-looking information, see *"Advisories Regarding Forward-Looking Statements"* in this MD&A.

BASIS OF PRESENTATION

All dollar amounts are referenced in thousands of Canadian dollars, except when noted otherwise. This MD&A contains various references to the abbreviation BOE which means barrels of oil equivalent. Where amounts are expressed on a BOE basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and is significantly different than the value ratio based on the current price of crude oil and natural gas. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Such abbreviation may be misleading, particularly if used in isolation.

FINANCIAL AND OPERATING SUMMARY

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas sales	**143,789**	125,064	15	**513,085**	468,432	10
Cash provided by operating activities	**62,804**	48,067	31	**264,256**	209,145	26
Adjusted funds from operations [(1)]	**76,817**	69,406	11	**261,525**	221,978	18
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Net income and comprehensive income	**19,064**	13,800	38	**63,058**	45,423	39
Diluted ($/common share)	**0.09**	0.07	29	**0.31**	0.23	35
Capital expenditures, net of A&D [(1)]	**42,806**	97,046	-56	**328,305**	333,147	-1
Bank debt	**179,861**	108,993	65	**179,861**	108,993	65
Net debt [(1)]	**189,703**	124,883	52	**189,703**	124,883	52
Return on average capital employed (%) [(1)]				**8**	6	33
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**45,102**	36,450	24	**40,397**	33,115	22
Net realized price, before derivative financial instruments [(1)]	**33.47**	36.31	-8	**33.63**	37.31	-10
Net realized price, after derivative financial instruments [(1)]	**35.27**	37.01	-5	**35.51**	37.66	-6
Operating netback [(1)]	**20.04**	21.80	-8	**19.43**	19.61	-1
Common shares outstanding (000s)	**199,805**	196,756	2	**199,805**	196,756	2
Reserves – proved plus probable (MBOE)	**448,304**	435,151	3	**448,304**	435,151	3

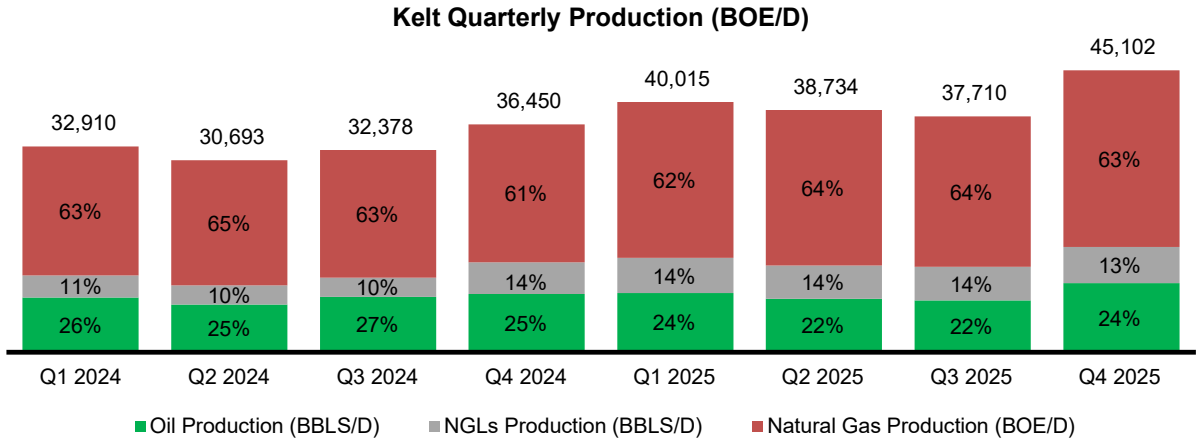
(1) Refer to advisories regarding non-GAAP and other financial measures.

Kelt's key financial and operating results in the fourth quarter of 2025 are highlighted by the following:

- **Production –** Average production of 45,102 BOE per day (37% liquids) increased 24% from 36,450 BOE per day (39%) liquids in the fourth quarter of 2024 and increased 20% from the third quarter of 2025.
- **Petroleum and natural gas sales –** Petroleum and natural gas sales increased 15% to $143.8 million from $125.1 million in the fourth quarter of 2024. Kelt's net realized price before derivative financial instruments of $33.47 per BOE decreased 8% from the fourth quarter of 2024, primarily due to lower oil and NGL prices.
- **Operating netback –** Kelt's operating netback was $20.04 per BOE for the fourth quarter of 2025, a decrease of 8% from $21.80 per BOE for the fourth quarter of 2024. This decrease was primarily driven by lower net realized oil and NGL prices relative to the prior period.
- **Cash provided by operating activities and adjusted funds from operations –** Cash provided by operating activities was $62.8 million compared to $48.1 million in the fourth quarter of 2024. Adjusted funds from operations of $76.8 million ($0.38 per common share, diluted) increased 11% compared to the fourth quarter of 2024 primarily due to higher production.
- **Net income –** Kelt reported net income of $19.1 million ($0.09 per common share, diluted) for the three months ended December 31, 2025, compared to net income of $13.8 million ($0.07 per common share, diluted) in the comparative period of 2024.
- **Capital investments –** During the fourth quarter of 2025, capital expenditures, net of A&D, was $42.8 million and included the drilling of 2.2 net wells, the completion of 2.0 net wells and included facilities, pipeline and well equipment spend of $20.4 million.
- **Net debt –** The Company ended the quarter with net debt of $189.7 million (0.7 times trailing 12-month adjusted funds from operations).
- **Reserves –** The Company ended the year with the following oil and gas reserves at December 31, 2025:

- Proved developed producing reserves of 83.5 million BOE (38% oil and NGLs), an increase of 6% from 78.9 million BOE at December 31, 2024;
- Total proved reserves of 265.1 million BOE (39% oil and NGLs), a slight decrease from 266.3 million BOE at December 31, 2024; and
- Total proved plus probable reserves of 448.3 million BOE (39% oil and NGLs), an increase of 3% from 435.2 million BOE at December 31, 2024.

PRODUCTION



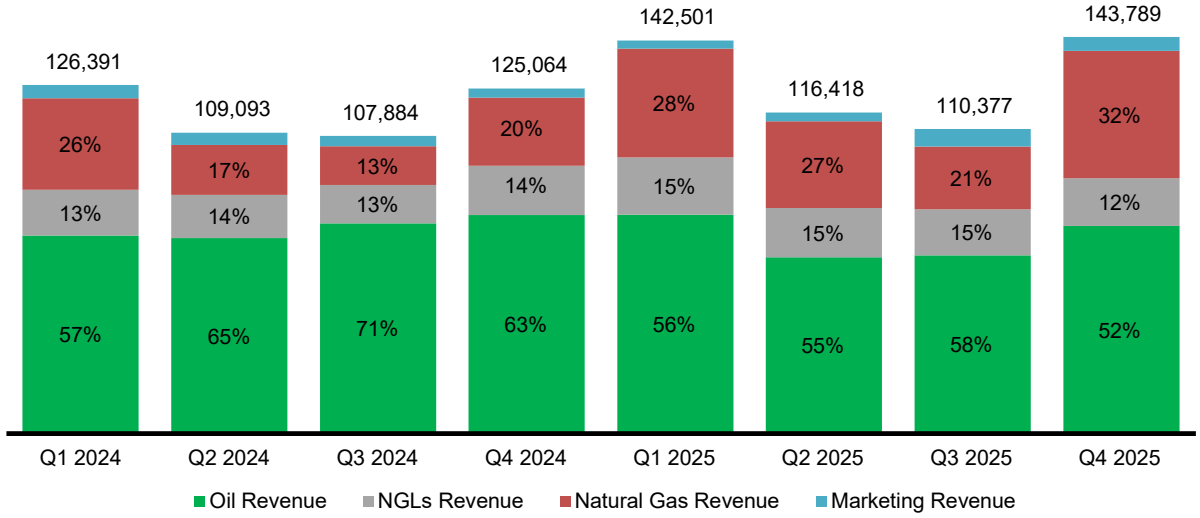
	Three months ended December 31			Year ended December 31		
	2025	2024	%	**2025**	2024	%
Average daily production:						
Oil (bbls/d)	**11,024**	9,297	19	**9,316**	8,623	8
NGLs (bbls/d)	**5,790**	5,052	15	**5,545**	3,675	51
Gas (mcf/d)	**169,725**	132,608	28	**153,214**	124,902	23
Combined (BOE/d)	**45,102**	36,450	24	**40,397**	33,115	22
Oil and NGLs weighting	**37%**	39%	-5	**37%**	37%	-

Average production for the fourth quarter of 2025 was 45,102 BOE per day, an increase of 24% from the fourth quarter of 2024. Average production for the year ended December 31, 2025 was 40,397 BOE per day, an increase of 22% from the year ended December 31, 2024. The increase in 2025 was primarily due to the Company's drilling activities and higher processing capacity at Wembley/Pipestone through the Albright Gas Plant which commenced operations during the fourth quarter of 2025.

Oil and NGLs weighting was 37% for the fourth quarter and year ended December 31, 2025, versus 39% and 37% for the fourth quarter and year ended December 31, 2024, respectively.

PETROLEUM AND NATURAL GAS SALES ("P&NG SALES")

Kelt Quarterly Petroleum and Natural Gas Sales ($000)



	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Oil	**75,190**	79,109	-5	**282,789**	297,920	-5
NGLs	**17,309**	17,893	-3	**72,749**	63,970	14
Gas	**46,220**	24,724	87	**139,852**	89,969	55
Marketing revenue [1]	**5,070**	3,338	52	**17,695**	16,573	7
P&NG Sales	**143,789**	125,064	15	**513,085**	468,432	10
Cost of purchases [2]	**(4,918)**	(3,305)	49	**(17,263)**	(16,365)	5
P&NG Sales after cost of purchases [3][5]	**138,871**	121,759	14	**495,822**	452,067	10
Net realized price ($/BOE) [4][5]	**33.47**	36.31	-8	**33.63**	37.31	-10

(1) Marketing revenue includes the sale of third-party volumes related to the Company's marketing of third-party oil production.

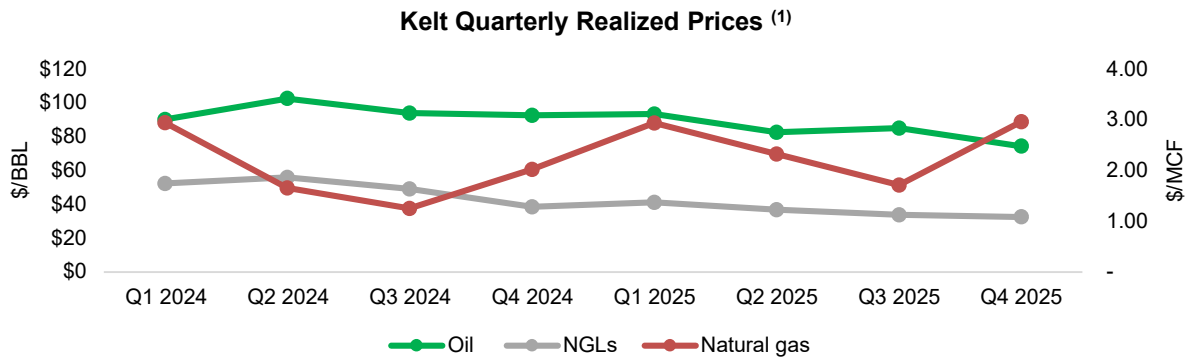
(2) Cost of purchases includes costs for the purchase of third-party volumes related to the Company's marketing of third-party oil production.

(3) P&NG sales after cost of purchases includes petroleum and natural gas sales, net of the cost of the third-party volumes purchased.

(4) Net realized price ($/BOE) equals P&NG sales after cost of purchases divided by total production.

(5) Refer to advisories regarding Non-GAAP and Other Financial Measures.

Petroleum and natural gas sales for the fourth quarter of 2025 were $143.8 million, an increase of 15% from $125.1 million for the fourth quarter of 2024. Petroleum and natural gas sales for the year ended December 31, 2025 were $513.1 million, an increase of 10% from the comparable period of 2024. The increase in P&NG sales from 2024 was due to an increase in production and an increase in realized natural gas prices, partially offset by lower realized oil and NGLs prices.



(1) Net realized prices are calculated based on Petroleum and Natural Gas Sales, less the cost of purchases of third-party volumes and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities. Net realized prices exclude both realized and unrealized gains and losses on risk management contracts. Refer to additional information under the heading of "Non-GAAP and Other Financial Measures".

	Three months ended December 31			Year ended December 31		
	2025	2024	%	**2025**	2024	%
Net realized prices [9]						
Oil ($/bbl)	**74.29**	92.53	-20	**83.29**	94.46	-12
NGLs ($/bbl)	**32.49**	38.50	-16	**35.94**	47.56	-24
Gas ($/Mcf)	**2.96**	2.02	47	**2.50**	1.97	27
Combined ($/BOE)	**33.47**	36.31	-8	**33.63**	37.31	-10
Average benchmark prices						
Oil and NGLs						
WTI Cushing Oklahoma (US$/bbl) [1]	**59.64**	70.69	-16	**65.43**	76.56	-15
Mixed Sweet Blend Edmonton ("MSW") ($/bbl) [2]	**77.27**	95.48	-19	**86.51**	98.70	-12
Edmonton Pentane ($/bbl) [3]	**81.01**	98.83	-18	**88.73**	100.55	-12
Edmonton Butane ($/bbl) [3]	**36.54**	55.70	-34	**40.57**	48.39	-16
Edmonton Propane ($/bbl) [3]	**21.58**	34.42	-37	**29.37**	30.39	-3
Edmonton Ethane ($/bbl) [3]	**6.31**	4.11	54	**4.67**	3.84	22
Natural Gas						
NYMEX Henry Hub (US$/MMBtu) [6]	**3.68**	2.42	52	**3.53**	2.25	57
AECO 5A (CA$/MMBtu) [4]	**2.23**	1.48	51	**1.68**	1.46	15
Chicago Alliance, into Interstates (CA$/MMBtu) [5]	**4.65**	3.08	51	**4.54**	2.82	61
Dawn (CA$/MMBtu) [5]	**4.80**	3.13	53	**4.54**	2.70	68
Sumas (CA$/MMBtu) [5]	**3.12**	3.03	3	**2.33**	2.74	-15
Station 2 (CA$/MMBtu) [7]	**1.85**	0.90	106	**1.00**	1.19	-16
Marcellus (TZ4 L300) (CA$/MMBtu) [5]	**4.12**	2.79	48	**3.88**	2.25	72
Average exchange rate (CA$/US$) [8]	**1.3949**	1.3990	-	**1.3978**	1.3700	2

(1) Source: U.S Energy Information Administration, Canadian dollar equivalent price WTI price ("CA$WTI") is calculated based on the monthly average US dollar WTI price and the monthly average CA$/US$ exchange rate (8).

(2) Source: Tidal Energy Marketing.

(3) Source: Sproule Associates Limited.

(4) Source: Canadian Gas Price Reporter converted to CA$/MMBtu using monthly average CA$/US$ exchange rate (8).

(5) Source: S&P Global Platts (US$/MMBtu) Daily Midpoint Average converted to CA$/MMBtu using monthly average CA$/US$ exchange rate (8).

(6) Source: S&P Global Platts (US$/MMBtu) Daily Midpoint Average.

(7) Source: S&P Global Platts (CA$/GJ) Daily Midpoint Average converted to CA$/MMBtu.

(8) Source: Bank of Canada.

(9) Net realized prices are calculated based on Petroleum and Natural Gas Sales, less the cost of purchases of third-party volumes and reflect Kelt's realized commodity prices plus the net benefit of oil blending and natural gas marketing activities. Net realized prices exclude both realized and unrealized gains and losses on derivative financial instruments. Refer to additional information under the heading of "Non-GAAP and Other Financial Measures".

Combined Net Realized Price

Kelt's combined net realized price decreased 8% to $33.47 per BOE in the fourth quarter of 2025 and decreased 10% to $33.63 per BOE for the year ended December 31, 2025. The decrease in the average realized price was due to a decrease in realized oil and NGLs prices partially offset by a higher realized natural gas price.

Oil prices

The mixed sweet blend benchmark crude oil price decreased 19% in the fourth quarter of 2025 and decreased 12% for the year ended December 31, 2025 versus the comparable periods of 2024. Benchmark crude oil prices decreased in 2025 primarily due to an increase of oil supply as OPEC+ announced its phasing out of its supply cuts in 2025 and into 2026.

NGL prices

For the three months and year ended December 31, 2025, realized NGLs price decreased 16% and 24%, respectively, as compared to the same period of 2024.

Kelt's realized NGLs price decreased in 2025 due to lower pentane, butane and propane benchmark prices. Pentane and butane prices generally follow the price of crude oil, which saw a decrease in 2025. Benchmark propane prices decreased in the fourth quarter of 2025 compared to the fourth quarter of 2024, due to rising storage levels in western Canada as a result of additional production growth and lower demand at the start of the 2025/2026 winter season. Propane prices for the year ended December 31, 2025 were slightly lower than previous year as lower prices in the fourth quarter were partially offset by higher prices for the nine months ending September 30, 2025.

Natural gas prices

Realized natural gas prices increased by 47% to $2.96 per Mcf in the fourth quarter of 2025 and by 27% to $2.50 per Mcf for the year ended December 31, 2025 versus the comparable periods of 2024. The increase in the Company's net realized natural gas price for the year ended December 31, 2025 was due to higher AECO natural gas benchmark prices, as well as Kelt's exposure to the US natural gas markets obtained through its diversified natural gas marketing portfolio, which was partially offset by lower Station 2 prices. US natural gas prices increased in 2025 compared to 2024 due to higher LNG exports and increased domestic demand offsetting higher supply. However, the Station 2 benchmark price decreased in 2025 versus 2024 due to higher-than-average western Canadian storage levels as a result of increased Canadian natural gas production more than offsetting higher demand, and a slower than anticipated start-up of LNG Canada. The Station 2 benchmark price increased at a higher rate than the other benchmark natural gas prices in the fourth quarter of 2025 as additional demand from LNG exports off the west coast of Canada started to impact price.

RISK MANAGEMENT AND HEDGING ACTIVITIES

The Company may enter into fixed price contracts and derivative financial instruments for commodity prices, currency exchange and interest rates in order to secure future cash flows or to protect a desired level of capital spending. Fair value accounting for derivative financial instruments may cause significant fluctuations in the reported amounts of derivative financial instrument assets and liabilities and the resultant magnitude of unrealized gains and losses.

Kelt recognized a gain of $11.7 million on derivative financial instruments for the fourth quarter of 2025 and a gain of $45.0 million for the year ended December 31, 2025. The unrealized gain on derivative financial instruments for the fourth quarter and year ended December 31, 2025 was primarily due to a decrease in the crude oil forward strip price at December 31, 2025 compared to December 31, 2024.

The realized gains on derivative financial instruments for both the quarter ended and year ended December 31, 2025 was due to a lower benchmark natural gas and crude oil price in 2025 compared to the derivative financial instrument contractual price.

The table below summarizes realized and unrealized gains (losses) on derivative financial instrument contracts:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Realized gains						
Derivative financial instruments - Oil	**4,355**	291	1,397	**8,581**	670	1,181
Derivative financial instruments - Gas	**2,683**	1,954	37	**17,958**	3,268	450
Derivative financial instruments - NGLs	**347**	108	221	**428**	315	36
Embedded derivative - Gas	**66**	-	-	**775**	-	-
Total realized gain	**7,451**	2,353	217	**27,742**	4,253	552
Unrealized gains (losses)						
Derivative financial instruments - Oil	**3,136**	(1,564)	-301	**10,541**	(2,455)	-529
Derivative financial instruments - Gas	**(647)**	(5,818)	-89	**4,194**	(3,436)	-222
Derivative financial instruments - NGLs	**98**	(186)	-153	**322**	(29)	-1,210
Embedded derivative - Gas	**1,653**	659	151	**2,185**	734	198
Total unrealized gain (loss)	**4,240**	(6,909)	-161	**17,242**	(5,186)	-432
Gain (loss) on derivative financial instruments	**11,691**	(4,556)	-357	**44,984**	(933)	-4,921
$ per BOE	**2.82**	(1.36)	-307	**3.05**	(0.08)	-3,913

Commodity price risk

Inherent to the business of producing oil and gas, the Company's cash provided by operating activities is subject to commodity price risk. Commodity price risk is the risk that future cash flows will fluctuate from changes in commodity prices. Commodity prices are impacted by world economic events that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and US dollar.

As of March 11, 2026, the following commodity price derivative financial instrument contracts are outstanding:

Crude oil derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
WTI fixed price [(1)]	500 bbl/d	CAD$92.85/bbl	Jan 26 – Mar 26
WTI fixed price	500 bbl/d	CAD$88.20/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$89.35/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.10/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.15/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.75/bbl	Jan 26 – Jun 26
WTI fixed price [(2)]	500 bbl/d	CAD$91.90/bbl	Jan 26 – Jun 26
WTI fixed price [(3)]	500 bbl/d	CAD$90.50/bbl	Jan 26 – Jun 26
WTI fixed price [(4)]	500 bbl/d	CAD$90.63/bbl	Jan 26 – Jun 26
WTI fixed price	300 bbl/d	CAD$130.00/bbl	Apr 26 – Jun 26
WTI fixed price	300 bbl/d	CAD$130.00/bbl	Apr 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$99.30/bbl	Apr 26 – Dec 26
WTI fixed price [(5)]	500 bbl/d	CAD$85.00/bbl	Jul 26 – Dec 26
WTI fixed price	500 bbl/d	CAD$87.65/bbl	Jul 26 – Sept 26
WTI fixed price	500 bbl/d	CAD$85.65/bbl	Oct 26 – Dec 26

(1) Includes a fixed price WTI ("West Texas Intermediate") oil swap option to sell 500 bbl/d for Apr-Jun 2026 at CAD$92.85/bbl exercisable on March 31, 2026.

(2) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$91.90/bbl exercisable on June 30, 2026.

(3) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.50/bbl exercisable on June 30, 2026.

(4) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.63/bbl exercisable on June 30, 2026.

(5) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Jun 2027 at CAD$85.00/bbl exercisable on December 31, 2026.

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane fixed price	250 bbl/d	USD$33.60/bbl	Jan 26 – Mar 26
OPIS-Conway propane	250 bbl/d	Monthly OPIS-Conway calculated at 46% of the floating monthly WTI price	Jan 26 – Mar 26

Natural gas derivative financial instrument

Contract Type	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX (1) call	20,000 MMBtu/d	USD$5.50/MMBtu	Jan 26 – Dec 26
AECO (2) 7A put	21,000 GJ/d	CAD$2.80/GJ	Jan 26 – Dec 26

(1) New York Mercantile Exchange ("NYMEX")

(2) Alberta Energy Company "C" Meter Station of the NOVA Pipeline System ("AECO")

Electricity derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
AESO (1) fixed price	24 MW/d	50.25 CAD per MWh	Feb 26 – Dec 26
AESO (1) fixed price	24 MW/d	45.25 CAD per MWh	Mar 26 – Dec 26

(1) Alberta Electric System Operator ("AESO")

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating AESO Power Pool Price divided by the fixed heat rate. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is calculated as the difference between the forecasted Floating AESO Power Pool Price divided by the fixed heat rate, less the forecasted AECO 5A price.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jan 26 – Dec 26

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating Japan/Korea Marker LNG Price multiplied by 22% and the Floating Dutch TTF Gas Price multiplied by 22%. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is based upon 22% of the future price in each respective market.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	5,000 MMBtu/d	Floating JKM (Japan/Korea Marker) Price (USD/MMBtu) multiplied by 22.0%	Jan 26 – Dec 26
Physical delivery	5,000 MMBtu/d	Floating TTF (Title Transfer Facility Netherlands) Price (USD/MMBtu) multiplied by 22.0%	Jan 26 – Dec 26

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Credit Facility which is subject to a floating interest rate. Based on bank debt balance as of December 31, 2025 of $179.9 million, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) annualized interest expense by $0.5 million. As of March 11, 2026, there are no interest rate risk management contracts outstanding.

Foreign exchange risk

Kelt is exposed to fluctuations of the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing and from exposure from certain U.S. dollar denominated natural gas marketing arrangements.

As of March 11, 2026, the following foreign exchange derivative financial instrument contracts are outstanding:

Foreign exchange derivative financial instrument			
Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward [(1)]	USD$2.0 million/month	$1.4025 CAD/USD	Jan 26 – Dec 26
Average rate forward	USD$1.0 million/month	$1.3800 CAD/USD	Feb 26 – Dec 26

(1) Contract includes an option that extends the contract into the 2027 calendar year at a strike price of $1.4025 CAD/USD if the spot CAD/USD is $1.4025 CAD/USD or higher on December 31, 2026. The contract also includes a knock out provision that if the spot CAD/USD trades at or below $1.3250 CAD/USD anytime between the trade date of November 3, 2025 to December 31, 2026, the option to extend into 2027 is cancelled.

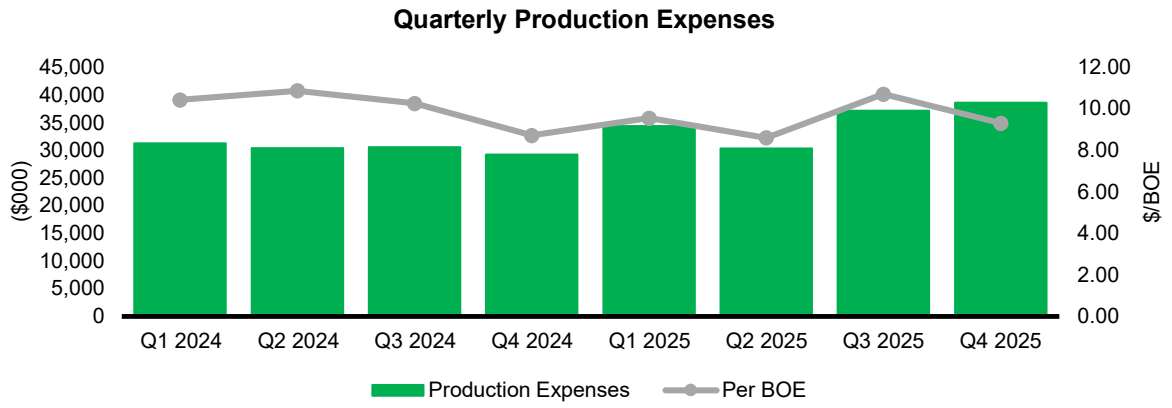
ROYALTIES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Royalties	**11,151**	9,552	17	**46,097**	54,737	-16
Average royalty rate [(1)]	**8.0%**	7.8%	3	**9.3%**	12.1%	-23
$ per BOE	**2.69**	2.85	-6	**3.13**	4.52	-31

(1) The average royalty rate is calculated based on total royalties as a percentage of "P&NG Sales, before marketing revenue" which excludes sales related to the sale of third-party production volumes used in oil blending operations (see table under the heading of *"Petroleum and Natural Gas Sales"*).

Kelt's average royalty rate was 8.0% and 9.3% for the three months and twelve months ended December 31, 2025 compared to 7.8% and 12.1% in the comparable periods of 2024, respectively. The decrease in the royalty rate for the year ended December 31, 2025 was primarily due to a higher percentage of producing wells that were eligible under the Alberta government's initial 5% royalty rate during 2025 compared to 2024. The royalty rate in the fourth quarter of 2025 was in-line with the royalty rate in the fourth quarter of 2024.

PRODUCTION EXPENSES

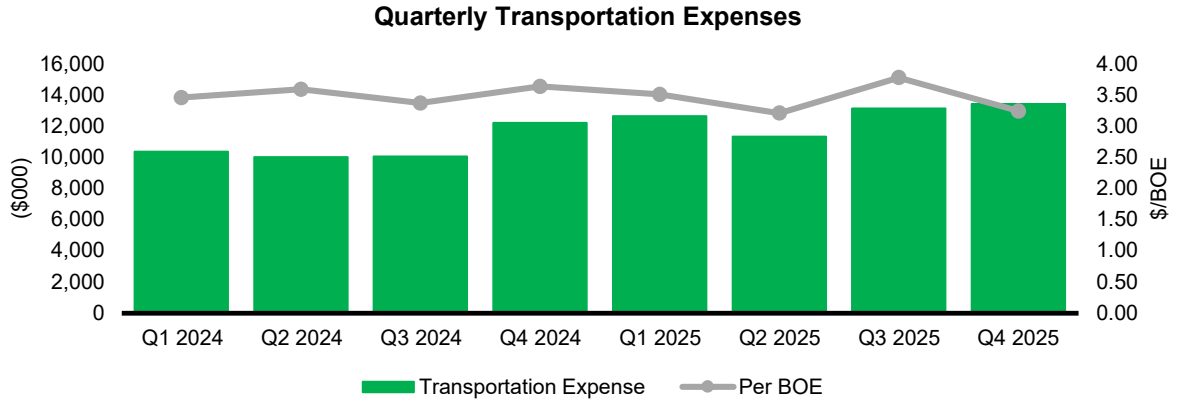


	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Production expense	**38,570**	29,235	32	**140,376**	121,355	16
$ per BOE	**9.30**	8.72	7	**9.52**	10.01	-5

Production expenses were $38.6 million during the fourth quarter of 2025, an increase of 32% compared to the fourth quarter of 2024. Production expenses averaged $9.30 per BOE during the fourth quarter of 2025, compared to $8.72 per BOE in the same period of 2024. Production expenses per BOE increased in the fourth quarter of 2025 primarily due to an equalization credit the Company received in the fourth quarter of 2024 that did not recur. This increase was partially offset by lower carbon taxes, utility costs, and field employee expenses in the fourth quarter of 2025.

Production expenses were $140.4 million for the year ended December 31, 2025, an increase of 16% compared to 2024. On a BOE basis, production expenses averaged $9.52 per BOE for 2025, compared to $10.01 per BOE in the same period of 2024. Production expenses per BOE decreased in 2025 primarily due to a decrease in utility costs and carbon taxes.

TRANSPORTATION EXPENSES



	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Transportation expense [(1)]	**13,426**	12,198	10	**50,507**	42,625	18
$ per BOE	**3.24**	3.64	-11	**3.43**	3.52	-3

(1) Pipeline tariffs are classified as transportation expenses when the Company has firm commitments or contractual arrangements on the pipeline. Pipeline tariffs may also be incurred indirectly by way of deduction from the base price paid by the purchasers of the Company's oil, NGLs and gas sales. In the latter case, and in the absence of a firm contractual obligation on the pipeline, the pipeline tariffs are presented as a reduction of revenue rather than as transportation expense.

Transportation expense averaged $3.24 per BOE during the fourth quarter of 2025 and $3.43 per BOE for the year ended December 31, 2025 compared to $3.64 per BOE during the fourth quarter of 2024 and $3.52 per BOE for the year ended December 31, 2024. Kelt's lower transportation costs per BOE in 2025 was primarily due to an increase in production for 2025, resulting in a higher percentage of gas volumes sold in the local western Canadian market resulting in lower transportation costs per BOE.

FINANCING EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Total interest expense	**3,348**	1,457	130	**11,330**	3,674	208
Accretion of decommissioning obligations	**833**	809	3	**3,264**	3,082	6
Financing expense	**4,181**	2,266	85	**14,594**	6,756	116
Interest expense per BOE [(1)]	**0.80**	0.43	86	**0.76**	0.30	153

(1) Interest expense used in the calculation of "Interest expense per BOE" includes interest and fees on bank debt.

Interest expense was $3.3 million for the fourth quarter of 2025 and $11.3 million for the year ended December 31, 2025. As at December 31, 2025, $179.9 million was drawn under the credit facility. In addition to the amounts drawn, the Company had $2.4 million in letters of credit.

Additional information regarding the credit facility is provided under the heading of *"Capital Resources and Liquidity"*.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

The following table summarizes significant components of the Company's G&A expenses:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Salaries and benefits	**3,240**	3,763	-14	**15,635**	14,855	5
Other G&A expenses	**1,388**	1,219	14	**6,175**	6,250	-1
Gross G&A expenses	**4,628**	4,982	-7	**21,810**	21,105	3
Overhead recoveries	**(1,638)**	(2,496)	-34	**(8,317)**	(8,833)	-6
Net G&A expenses	**2,990**	2,486	20	**13,493**	12,272	10
Gross G&A ($ per BOE)	**1.12**	1.49	-25	**1.48**	1.74	-15
Net G&A ($ per BOE)	**0.72**	0.74	-3	**0.92**	1.01	-9

Gross G&A expenses were overall in-line with the prior year, with a 7% decrease in the fourth quarter of 2025 and a 3% increase for the year ended December 31, 2025 compared to the same periods of 2024. Net G&A expenses per BOE decreased by 9 percent in 2025 compared to 2024.

SHARE BASED COMPENSATION ("SBC")

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Stock options	**589**	1,376	-57	**3,114**	5,266	-41
Restricted share units ("RSUs")	**958**	973	-2	**3,530**	3,580	-1
Performance share units ("PSUs")	**470**	-	-	**1,169**	-	-
Total SBC expense	**2,017**	2,349	-14	**7,813**	8,846	-12
$ per BOE	**0.49**	0.70	-30	**0.53**	0.73	-27

In April 2025, the Company's shareholders approved a PSU plan which replaced the Company's Stock Option Plan after which no further stock options will be issued.

The decrease in SBC expense for the quarter and year ended December 31, 2025 was primarily due to a lower initial expense of the PSU's compared to the previous stock option grants.

As at December 31, 2025, stock options, RSUs, and PSUs outstanding represent 5.0% of total shares outstanding (December 31, 2024 – 6.0%).

DEPLETION AND DEPRECIATION

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Depletion and depreciation	**53,065**	40,539	31	**183,571**	141,494	30
$ per BOE	**12.79**	12.09	6	**12.45**	11.67	7

Depletion and depreciation expense increased by 31% for the quarter ended December 31, 2025 and increased by 30% for the year ended December 31, 2025, as compared to the same periods of 2024. The increase was primarily due to an increase in production. For the three months and year ended December 31, 2025, the depletion and depreciation expense per BOE increased by 6% and 7% compared to the same periods of 2024.

Based on its assessment as of December 31, 2025, the Company determined that there were no indicators of impairment.

INCOME TAXES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Deferred income tax expense	**6,135**	4,931	24	**20,933**	17,733	18
Net income before taxes	**25,199**	18,731	35	**83,991**	63,156	33
Effective tax rate	**24.3%**	26.3%	-8	**24.9%**	28.1%	-11

Kelt's consolidated combined federal and provincial statutory tax rate averaged 23% during the three months ended December 31, 2025 and 2024.

Kelt was not required to pay income taxes in the current or prior year. Tax pools and losses available to reduce taxable income as of December 31, 2025 are estimated to be approximately $966.7 million as summarized in the table below.

(CA$ thousands, except as otherwise indicated)	Rate	**December 31 2025**	December 31 2024	%
Canadian oil and gas property expenses (COGPE)	10%	**53,763**	58,536	-8
Canadian development expenses (CDE)	30%	**325,828**	301,401	8
Canadian exploration expenses (CEE)	100%	**14,472**	1,019	1,320
Undepreciated capital cost [(1)] (UCC)	25%	**298,783**	262,970	14
Non-capital losses [(2)] (NCL)	100%	**273,812**	272,819	-
Estimated tax deductions available, end of period		**966,658**	896,745	8

(1) The majority of the Company's undepreciated capital cost deductions relate to Class 41 assets, which are deductible at a rate of 25% per year.
(2) The Company's non-capital losses expire in years 2035 to 2045.

ADJUSTED FUNDS FROM OPERATIONS

The following table provides a continuity of income and expenses included in the Company's calculation of operating income, operating netback and adjusted funds from operations generated during the three months and year ended December 31, 2025 and 2024 respectively.

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Petroleum and natural gas sales	**143,789**	125,064	15	**513,085**	468,432	10
Cost of purchases	**(4,918)**	(3,305)	49	**(17,263)**	(16,365)	5
Realized gain on derivative financial instruments [1]	**7,451**	2,353	217	**27,742**	4,253	552
Royalties	**(11,151)**	(9,552)	17	**(46,097)**	(54,737)	-16
Production expense	**(38,570)**	(29,235)	32	**(140,376)**	(121,355)	16
Transportation expense	**(13,426)**	(12,198)	10	**(50,507)**	(42,625)	18
Operating Income [2]	**83,175**	73,127	14	**286,584**	237,603	21
Financing expense [3]	**(3,348)**	(1,457)	130	**(11,330)**	(3,674)	208
G&A expense	**(2,990)**	(2,486)	20	**(13,493)**	(12,272)	10
Gain (loss) on foreign exchange	**(33)**	219	-115	**(277)**	204	-236
Other income	**13**	3	333	**41**	117	-65
Adjusted funds from operations [2]	**76,817**	69,406	11	**261,525**	221,978	18
Basic ($ per common share) [4]	**0.39**	0.35	11	**1.32**	1.13	17
Diluted ($ per common share) [4]	**0.38**	0.35	9	**1.29**	1.11	16

	Three months ended December 31			Year ended December 31		
($ per BOE)	**2025**	2024	%	**2025**	2024	%
Petroleum and natural gas sales	**34.66**	37.30	-7	**34.80**	38.66	-10
Cost of purchases	**(1.19)**	(0.99)	20	**(1.17)**	(1.35)	-13
Realized gain on derivative financial instruments [1]	**1.80**	0.70	157	**1.88**	0.35	437
Royalties	**(2.69)**	(2.85)	-6	**(3.13)**	(4.52)	-31
Production expense	**(9.30)**	(8.72)	7	**(9.52)**	(10.01)	-5
Transportation expense	**(3.24)**	(3.64)	-11	**(3.43)**	(3.52)	-3
Operating Netback [2]	**20.04**	21.80	-8	**19.43**	19.61	-1
Financing expense [3]	**(0.80)**	(0.43)	86	**(0.76)**	(0.30)	153
G&A expense	**(0.72)**	(0.74)	-3	**(0.92)**	(1.01)	-9
Gain (loss) on foreign exchange	**(0.01)**	0.07	-114	**(0.01)**	0.02	-150
Other income	**-**	-	-	**-**	0.01	-100
Adjusted funds from operations [2]	**18.51**	20.70	-11	**17.74**	18.33	-3

(1) Includes realized gains (losses) on commodity price and foreign exchange derivative financial instruments.

(2) Refer to advisories regarding *"*Non-GAAP and Other Financial Measures*"*.

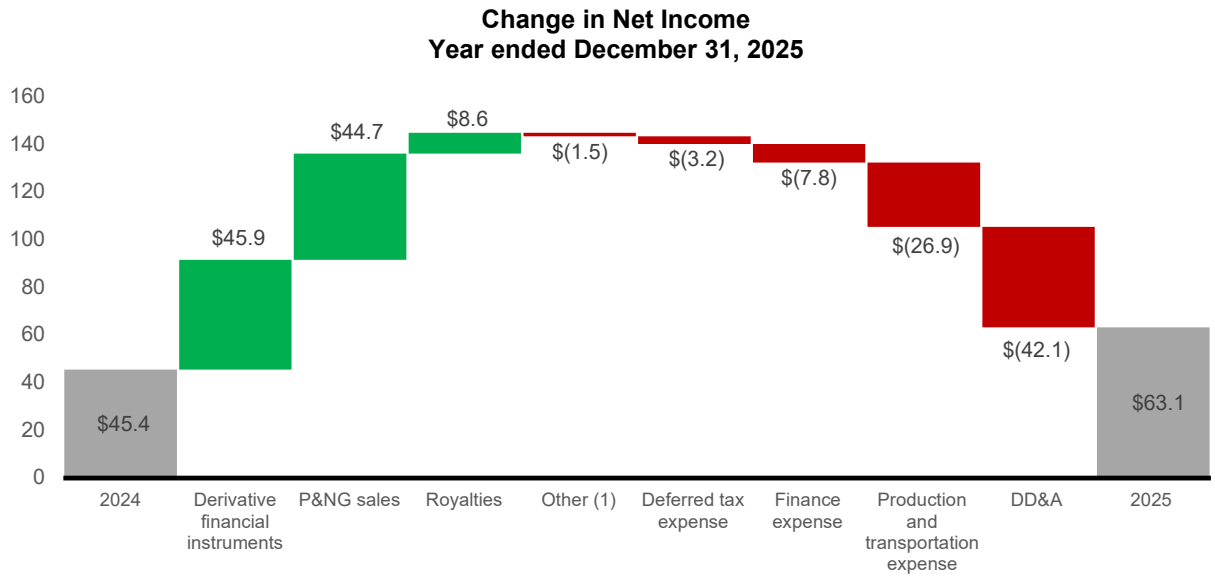
(3) Excludes non-cash accretion of decommissioning obligations.

(4) Adjusted funds from operations (2) per common share is calculated on a consistent basis with net income per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP.

During the three months ended December 31, 2025, adjusted funds from operations of $76.8 million ($0.38 per common share, diluted) increased by 11% from $69.4 million ($0.35 per common share, diluted) in the fourth quarter of 2024. The increase in adjusted funds from operations in the fourth quarter of 2025 compared to 2024 was primarily due to an increase in petroleum and natural gas sales, higher realized gains on derivative financial instruments, partially offset by higher production expenses.

During the year ended December 31, 2025, adjusted funds from operations of $261.5 million ($1.29 per common share, diluted) increased by 18% from $222.0 million ($1.11 per common share, diluted) during the year ended December 31, 2024. The increase in adjusted funds from operations for the year ended December 31, 2025 compared to the same period of 2024 was primarily due to an increase in petroleum and natural gas sales, higher realized gains on derivative financial instruments, and a decrease in royalties, partially offset by an increase in production and transportation expenses.

NET INCOME AND COMPREHENSIVE INCOME



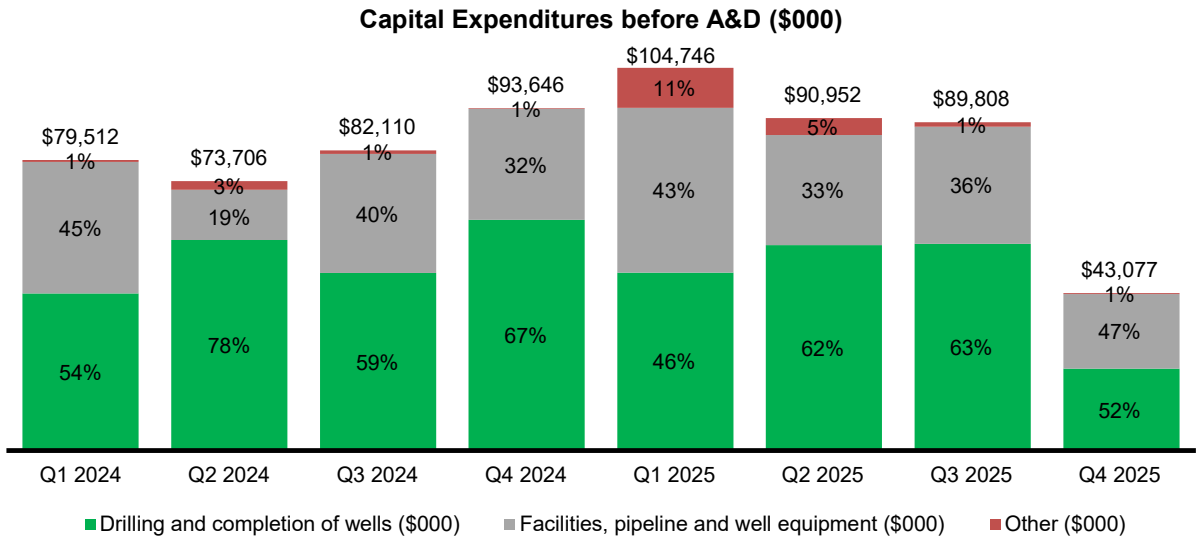
(1) Other includes changes in net income related primarily to cost of purchases, G&A expense, share based compensation, and foreign exchange gain (loss).

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Net income and comprehensive income	**19,064**	13,800	38	**63,058**	45,423	39
$ per common share, basic	**0.10**	0.07	43	**0.32**	0.23	39
$ per common share, diluted [1]	**0.09**	0.07	29	**0.31**	0.23	35
$ per BOE	**4.59**	4.12	11	**4.28**	3.76	14
Wtd avg. shares outstanding, basic (000s)	**199,516**	196,557	2	**198,838**	195,719	2
Wtd avg. shares outstanding, diluted (000s) [1]	**203,089**	200,801	1	**202,105**	199,631	1

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share.

Net income was $19.1 million ($0.09 per common share, diluted) for the three months ended December 31, 2025, compared to a net income of $13.8 million ($0.07 per common share, diluted) in the same three month period of 2024. Net income was $63.1 million ($0.31 per common share, diluted) for the year ended December 31, 2025, compared to a net income of $45.4 million ($0.23 per common share, diluted) in the same period of 2024. The increase in net income in 2025 was primarily driven by an increase in petroleum and natural gas sales, higher gains on derivative financial instruments, which was partially offset by higher depletion and depreciation and an increase in production and transportation expenses.

INVESTING ACTIVITIES



CAPITAL EXPENDITURES

The Company's capital expenditures, before and net of acquisitions and dispositions ("A&D"), are summarized in the following table:

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Capital expenditures:						
Lease acquisition and retention	**221**	93	138	**2,252**	2,345	-4
Geological and geophysical	**-**	23	-100	**13,905**	610	2,180
Drilling and completion of wells	**22,356**	63,061	-65	**183,754**	212,141	-13
Facilities, pipeline and well equipment	**20,443**	30,394	-33	**127,691**	112,738	13
Corporate assets	**57**	75	-24	**981**	1,140	-14

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2025**	2024	%	**2025**	2024	%
Capital expenditures, before A&D [(1)]	**43,077**	93,646	-54	**328,583**	328,974	-
Property acquisitions	**(96)**	3,500	-103	**217**	4,816	-95
Property dispositions	**(175)**	(100)	75	**(495)**	(643)	-23
Capital expenditures, net of A&D [(1)]	**42,806**	97,046	-56	**328,305**	333,147	-1

(1) Refer to advisories regarding "Non-GAAP and Other Financial Measures".

Capital expenditures, before A&D, decreased 54% in the fourth quarter of 2025. Total capital expenditures for the year ended December 31, 2025 were relatively consistent with the comparable period of 2024.

In the fourth quarter of 2025, drilling and completion costs of $22.4 million included the drilling of 2.2 net wells, the drilling of 1.0 net service wells, and the completion of 2.0 net wells. Kelt's facility, pipeline and well equipment spending in the fourth quarter of 2025 of $20.4 million focused on well equipment, pipeline construction and facility optimization.

For the year ended December 31, 2025, drilling and completion costs of $183.8 million included the drilling of 27.8 net wells, the drilling of 2.0 net service wells, and the completion of 26.6 net wells. The wells drilled included 22 gross (22 net) Montney wells and 8 gross (5.2 net) Charlie Lake wells. Kelt's facility, pipeline and well equipment spending in 2025 of $127.7 million focused on facility expansions, pipeline construction and well equipment.

	Three months ended December 31			Year ended December 31		
Gross Wells	**2025**	2024	%	**2025**	2024	%
Drilling	**3**	3	-	**33**	34	-3
Completion	**2**	12	-83	**31**	34	-9
Service	**1**	-	-	**2**	1	100

	Three months ended December 31			Year ended December 31		
Net Wells	**2025**	2024	%	**2025**	2024	%
Drilling	**2.2**	3.0	-27	**27.8**	31.3	-11
Completion	**2.0**	12.0	-83	**26.6**	31.3	-15
Service	**1.0**	-	-	**2.0**	1.0	100

LAND HOLDINGS

The table below sets-out Kelt's significant Montney and Charlie Lake land holdings across British Columbia and Alberta as at December 31, 2025.

MONTNEY RIGHTS	**Net Acres**	Net Sections
British Columbia	**193,607**	302
Alberta	**164,853**	258
Total	**358,460**	560
CHARLIE LAKE RIGHTS		
Alberta	**89,326**	140

CAPITAL RESOURCES AND LIQUIDITY

Kelt's objective is to maintain a flexible capital structure that provides sufficient liquidity for the Company to meet its obligations when due and to execute on its capital investment program. The Company manages its capital structure in response to changes in economic conditions and the risk characteristics of its underlying oil and natural gas assets.

The Company has a $300.0 million credit facility from a syndicate of financial institutions. At December 31, 2025, $179.9 million was drawn under the Credit Facility. In addition to the amounts drawn, the Company had $2.4 million in letters of credit. The Credit Facility may be extended annually at Kelt's option and subject to lender approval, with a 364 day term-out period if not renewed.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount. The credit facility is subject to semi-annual redeterminations on or before June 30 and November 30 of each year. There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. Covenants include industry standard positive and negative covenants including reporting requirements, permitted indebtedness, permitted risk management activities, permitted encumbrances and other standard business operating covenants. Security is provided for by a demand debenture with a floating charge over all assets in the amount of $800.0 million.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on the prime rate plus the applicable margin. The applicable margin ranges from 175 basis points to 375 basis points depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times. Under the Credit Facility, borrowings through the use of CORRA term loans are also available. Stamping fees fluctuate based on a pricing grid and range from 2.75% to 4.75%, depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times.

	December 31, 2025	December 31, 2024
Bank debt	**179,861**	108,993
Accounts payable and accrued liabilities	**78,046**	80,463
Cash and cash equivalents	**(90)**	(228)
Accounts receivable and accrued sales	**(64,195)**	(60,236)
Prepaid expenses and deposits	**(3,919)**	(4,109)
Net debt [(1)]	**189,703**	124,883
Adjusted funds from operations [(1)]	**261,525**	221,978
Net debt to adjusted funds from operations ratio [(1)]	**0.7**	0.6

(1) Refer to advisories regarding Capital Management Measures.

The Company monitors its capital structure and short-term financing requirements using a net debt to adjusted funds from operations ratio, which is a non-GAAP financial measure. Kelt targets a net debt to adjusted funds from operations ratio of less than 2.0 times.

The Company may adjust its future capital structure and capital expenditures according to market conditions to maintain flexibility to achieve its objectives. In doing so, the Company may increase or decrease capital expenditures including acquisitions and dispositions, issue new shares, issue new debt or repay existing debt.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at December 31, 2025:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	78,046	-	-	**78,046**
Derivative financial instruments	1,033	-	-	**1,033**
Lease liability	633	385	-	**1,018**
Bank debt and estimated interest [(1)]	10,792	179,861	-	**190,653**
Total	**90,504**	**180,246**	**-**	**270,750**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 6.0% for the year ended December 31, 2025, applied to the principal balance outstanding as at that date.

COMMITMENTS

As of December 31, 2025, the Company is committed to future payments under the following agreements:

	2026	2027	2028	2029	2030	Thereafter
Firm processing commitments	67,400	72,067	78,513	79,285	80,519	400,807
Firm transportation commitments	47,777	48,215	51,911	41,143	33,768	110,874
Total commitments	**115,177**	**120,282**	**130,424**	**120,428**	**114,287**	**511,681**

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. At December 31, 2025 there were 199.8 million common shares issued and outstanding. There are no preferred shares issued or outstanding.

At December 31, 2025, officers, directors, and employees have been granted options to purchase 7.5 million common shares at an average exercise price of $5.02 per common share. In addition, there are 1.7 million RSUs and 0.7 million PSUs outstanding.

RELATED PARTY TRANSACTIONS

The Company has engaged the services of a registrar and transfer agent where an officer of Kelt is a director of the company. During the year ended December 31, 2025, the Company incurred $0.2 million (December 31, 2024 – $0.1 million) in disbursements to this related party. As of December 31, 2025, the Company no longer considers a law firm, where a Kelt Board Member was previously a partner at, to be a related party.

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Company. The following table summarizes compensation paid or payable to officers and directors of the Company:

	Year ended December 31	
	2025	2024
Salaries, bonuses and other benefits	**3,589**	3,509
Share based compensation	**3,665**	3,870
Total compensation	**7,254**	7,379

During the year ended December 31, 2025, key management personnel were granted 211,138 RSUs, and 351,918 PSUs. During the year ended December 31, 2024, key management personnel were granted 935,000 stock options with an exercise price of $6.06 per share and 173,000 RSUs.

OFF-BALANCE SHEET TRANSACTIONS

The Company did not engage in any off-balance sheet transactions during the periods ended December 31, 2025 and 2024.

RESERVES

Kelt retained McDaniel & Associates Consultants Ltd ("McDaniel"), an independent qualified reserve evaluator to prepare a report on its oil and gas reserves (the "McDaniel Report"). The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2025 and at December 31, 2024 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). The McDaniel Report is effective as of December 31, 2025. More information on the Company's reserves are included in the Annual Information Form as at December 31, 2025, dated March 11, 2026, which can be found at www.sedarplus.ca.

At December 31, 2025, Kelt's proved plus probable reserves were 448.3 million BOE, up 3% from 435.2 million BOE at December 31, 2024. The Company's net present value of proved plus probable reserves at December 31, 2025, discounted at 10% before-tax, was $3.3 billion, a decrease of 5% from $3.5 billion at December 31, 2024. McDaniel's forecast commodity prices for 2026 which were used to determine the present value of the Company's reserves at December 31, 2025, are US$59.92 per barrel for WTI oil and US$3.74 per MMBtu for NYMEX Henry Hub.

At December 31, 2025, the weighting of proved plus probable reserves was 39% oil/NGLs and 61% natural gas. At December 31, 2024, the weighting of proved plus probable reserves was 40% oil/NGLs and 60% natural gas.

The following table outlines a summary of the Company's reserves volumes at December 31, 2025:

SUMMARY OF RESERVE VOLUMES	Crude Oil (Mbbls)	Liquids[1] (Mbbls)	Natural Gas (MMcf)	**Combined[2] (MBOE)**	**FDC Costs ($ thousands)**
Proved developed producing	15,981	15,906	309,575	**83,482**	**-**
Proved	54,291	48,513	973,675	**265,084**	**1,928,264**
Proved plus Probable	95,727	79,720	1,637,146	**448,304**	**3,114,855**

(1) "Liquids" include field condensate and NGLs.
(2) Numbers may not add due to rounding.

CHANGE IN RESERVES – YEAR OVER YEAR (MBOE)	December 31 2025	December 31 2024	% Change
Proved developed producing	**83,482**	78,862	6
Proved	**265,084**	266,312	-
Proved plus Probable	**448,304**	435,151	3

The following table outlines forecasted future prices that McDaniel has used in their evaluation of the Company's reserves at December 31, 2025:

FUTURE COMMODITY PRICE FORECAST	WTI Cushing Oklahoma US$/bbl	Canadian Light Sweet CA$/bbl	NYMEX Henry Hub US$/MMBtu	AECO-C Spot CA$/GJ	USD/CAD Exchange US$/CA$
2026	59.92	77.54	3.74	2.84	1.37
2027	65.10	83.60	3.78	3.13	1.35
2028	70.28	90.17	3.85	3.31	1.35
2029	71.93	92.32	3.93	3.39	1.35
2030	73.37	94.17	4.01	3.46	1.35
Five year average	**68.12**	**87.56**	**3.86**	**3.23**	**1.36**

The following table summarizes the net present value of the Company's reserves (before-tax) as at December 31, 2025:

NET PRESENT VALUE (BEFORE-TAX) *(CA$ millions)*	Undiscounted	NPV 5% BT	NPV 10% BT
Proved developed producing	1,147,144	1,024,007	887,348
Proved	3,535,183	2,598,009	1,961,806
Proved plus Probable	7,051,603	4,683,113	3,311,340

SUMMARY OF QUARTERLY RESULTS

The following tables summarize the Company's financial and operating results over the past eight quarters:

(CA$ thousands, except as otherwise indicated)	**Q4 2025**	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Revenue	**132,638**	100,142	106,946	127,262	115,512	94,985	91,849	111,349
Cash provided by operating activities	**62,804**	53,827	60,696	86,929	48,067	52,166	46,419	62,493
Adjusted funds from operations [(1)]	**76,817**	44,648	61,846	78,214	69,406	48,939	42,457	61,176
Per share – basic ($/common share) [(1)]	**0.39**	0.22	0.31	0.40	0.35	0.25	0.22	0.31
Per share – diluted ($/common share) [(1)]	**0.38**	0.22	0.31	0.39	0.35	0.24	0.21	0.31
Net income (loss) and comprehensive net income (loss)	**19,064**	(7,446)	32,461	18,979	13,800	8,871	10,905	11,847
Per share – basic ($/common share)	**0.10**	(0.04)	0.16	0.10	0.07	0.05	0.06	0.06
Per share – diluted ($/common share)	**0.09**	(0.04)	0.16	0.09	0.07	0.04	0.05	0.06
Capital expenditures, net of A&D [(1)]	**42,806**	89,801	90,952	104,746	97,046	82,110	73,810	80,181
Total assets	**1,600,515**	1,594,538	1,562,599	1,512,752	1,450,679	1,378,621	1,328,148	1,282,456
Bank debt	**179,861**	186,000	151,432	102,766	108,993	45,428	12,611	-
Net debt [(1)]	**189,703**	223,684	178,170	150,024	124,883	95,889	63,084	31,961
Shareholders' equity	**1,139,639**	1,117,150	1,121,679	1,086,264	1,063,004	1,046,142	1,033,204	1,018,604
Average daily production (BOE/d)	**45,102**	37,710	38,734	40,015	36,450	32,378	30,693	32,910
Combined net realized price ($/BOE) [(1)(2)]	**35.27**	32.12	34.00	40.53	37.01	35.86	37.18	40.59

(CA$ thousands, except as otherwise indicated)	**Q4 2025**	**Q3 2025**	**Q2 2025**	**Q1 2025**	**Q4 2024**	**Q3 2024**	**Q2 2024**	**Q1 2024**
Operating netback ($/BOE) [1]	**20.04**	14.69	19.50	23.25	21.80	17.91	16.55	21.69
Operating netback % of combined net realized price [2]	**57%**	46%	57%	57%	59%	50%	45%	53%

(1) Refer to advisories regarding *"Non-GAAP and Other Financial Measures"*.

(2) In this table, combined net realized prices are after derivative financial instruments.

Kelt's business objective is for long-term profitable growth by implementing a full cycle exploration and development program. Over the past eight quarters, Kelt has focused its cash provided from operating activities on its development capital program which has resulted in higher average daily production and adjusted funds from operations.

Refer to the *"Financial and Operating Summary"* section of this MD&A for further discussion. Additional information relating to Kelt, including the Company's MD&A for previous quarters, is filed on SEDAR+ and can be viewed at www.sedarplus.ca.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

(CA$ thousands, except as otherwise indicated)	**2025**	2024	2023
Revenues	**466,988**	413,695	436,410
Cash provided by operating activities	**264,256**	209,145	283,224
Adjusted funds from operations [1]	**261,525**	221,978	276,200
Per share – basic ($/common share) [1]	**1.32**	1.13	1.43
Per share – diluted ($/common share) [1]	**1.29**	1.11	1.40
Net income and comprehensive income	**63,058**	45,423	85,974
Per share – basic ($/common share)	**0.32**	0.23	0.45
Per share – diluted ($/common share)	**0.31**	0.23	0.44
Capital expenditures, net of A&D [1]	**328,305**	333,147	282,646
Total assets	**1,600,515**	1,450,679	1,260,292
Bank debt	**179,861**	108,993	-
Net debt [1]	**189,703**	124,883	12,997
Shareholders' equity	**1,139,639**	1,063,004	1,003,663
Return on average capital employed (%) [1]	**8**	6	12
Average daily production (BOE/d)	**40,397**	33,115	30,510
Combined net realized price ($/BOE) [1][2]	**35.51**	37.66	44.36
Operating netback ($/BOE) [1]	**19.43**	19.61	25.74
Operating netback as a % of combined net realized price [2]	**55%**	52%	58%

(1) Refer to advisories regarding *"Non-GAAP and Other Financial Measures"*.

(2) In this table, average realized prices are after derivative financial instruments.

OUTLOOK AND GUIDANCE

The table below compares the Company's previously forecasted assumptions and expected financial and operating results for 2025 to actual 2025 results:

(CA$ millions, except as otherwise indicated)	**2025 Actuals**	2025 Forecast	% Change
Average Production			
Oil and NGLs (bbls/d)	**14,861**	14,600 – 15,400	-
Gas (MMcf/d)	**153.2**	152.4 – 153.6	-
Combined (BOE/d)	**40,397**	40,000 – 41,000	-
Forecasted Average Commodity Prices			
WTI (US$/bbl)	**65.43**	66.00	-1
Canadian Light Sweet ($/bbl)	**86.51**	87.54	-1
NYMEX (US$/MMBtu)	**3.53**	3.50	1
Dawn (US$/MMBtu)	**3.24**	3.30	-2
AECO ($/GJ)	**1.59**	1.73	-8
Station 2 ($/GJ)	**0.95**	1.19	-20
Average Exchange Rate (US$/CA$)	**0.7154**	0.7161	-
Capital expenditures, net of A&D (1)	**328.3**	325.0	1
Petroleum and natural gas sales	**513.1**	536.1	-4
Adjusted funds from operations (1)	**261.5**	280.0	-7
Per common share, diluted (1)	**1.29**	1.38	-7
Net debt, at year end (1)	**189.7**	170.0	12
Weighted average common shares outstanding (millions) (1)	**198.8**	198.8	-

(1) Refer to advisories regarding "Non-GAAP and Other Financial Measures".

2026 BUDGET

The table below outlines the Company's current 2026 forecast compared to the previous 2026 forecast which was included in Kelt's press release dated January 5, 2026:

(CA$ millions, except as otherwise indicated)	**Current 2026 Forecast**	Previous 2026 Forecast (January 5, 2026)	2025 Actuals	% Change current 2026 forecast to previous 2026 forecast [2]
Average Production				
Oil and NGLs (bbls/d)	**19,100 – 20,100**	19,100 – 20,100	14,861	-
Gas (MMcf/d)	**185.4 – 191.4**	185.4 – 191.4	153.2	-
Combined (BOE/d)	**50,000 – 52,000**	50,000 – 52,000	40,397	-
Forecasted Average Commodity Prices				
WTI (US$/bbl)	**69.40**	59.00	65.43	18
Canadian Light Sweet ($/bbl)	**89.65**	76.80	86.51	17
NYMEX (US$/MMBtu)	**3.80**	3.80	3.53	-
Dawn (US$/MMBtu)	**3.60**	3.60	3.24	-
AECO ($/GJ)	**2.33**	2.80	1.59	-17
Station 2 ($/GJ)	**2.27**	2.80	0.95	-19
Average Exchange Rate (US$/CA$)	**0.7331**	0.7260	0.7154	1
Capital Expenditures, net of A&D [1]	**355.0**	355.0	328.3	-
Petroleum and natural gas sales	**722.6**	682.0	513.1	6
Adjusted funds from operations [1]	**375.0**	355.0	261.5	6
Per common share, diluted [1]	**1.83**	1.73	1.29	6
Net debt, at year end [1]	**170.0**	170.0	189.7	-
Weighted average common shares outstanding (millions) [1]	**201.3**	201.3	198.8	-

(1) Refer to advisories regarding *"*Non-GAAP and Other Financial Measures*"*.

(2) Percent change for production is calculated using the mid-point of each production range.

Forecasted average production for 2026 remains at approximately 50,000 to 52,000 BOE per day. WTI crude oil prices are forecasted to average US$69.40 per barrel, an increase of 18% from the Company's previous guidance. Forecasted AECO natural gas prices decreased by 17% to average $2.33 per GJ and forecasted Station 2 natural gas prices decreased by 19% to average $2.27 per GJ.

After giving effect to the changes in commodity price assumptions, Kelt is forecasting 2026 petroleum and natural gas sales of $722.6 million and adjusted funds from operations to be $375.0 million, an increase of 6% from the previous forecast. Capital expenditures of $355.0 million in 2026 and net debt as of December 31, 2026 of $170.0 million remain unchanged from the previous guidance.

A 10% increase/decrease in the Company's forecasted average oil/NGLs price in 2026 would increase/decrease forecasted adjusted funds from operations in 2026 by approximately $26.9 million. A 10% increase/decrease in the Company's average natural gas price in 2026 would increase/decrease adjusted funds from operations in 2026 by approximately $16.0 million.

SIGNIFICANT JUDGMENTS AND ESTIMATES

The material accounting policies applied by the Company are disclosed in note 3 of the consolidated financial statements as at and for the year ended December 31, 2025. The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ materially from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in the consolidated annual financial statements are discussed below.

- Estimates are used in the evaluation of proved and proved plus probable reserves. Reserve estimates are based on production forecasts, future production costs, forecasted commodity prices and future development capital. Proved reserves and future development capital are used to deplete the net carrying value of property, plant, and equipment ("PP&E"). Proved reserves are used in the determination of depletion expense. Proved plus probable reserves are used to measure the fair value less cost of disposal ("FVLCD") in calculating impairment of PP&E. Reserves also impact the assessment of the commercial viability and technical feasibility of an exploration project which impacts the decision to transfer exploration and evaluation assets ("E&E") to PP&E or whether an impairment exists;
- The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The FVLCD is calculated on a CGU basis to determine whether there is an impairment of PP&E;
- The determination of the value of decommissioning liabilities depends upon estimates of future costs, timing of expenditures, the risk-free rate and inflation rate;
- Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. As such, deferred income taxes are subject to measurement uncertainty; and
- Estimates and assumptions are used in the Black-Scholes option pricing model to calculate the stock based compensation expense.

For more details regarding the Company's use of estimates and judgements, refer to note 2c) of the consolidated financial statements as at and for the year ended December 31, 2025.

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and the CFO have evaluated the effectiveness of Kelt's disclosure controls and procedures as at December 31, 2025 and have concluded that such disclosure controls and procedures are effective. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

There were no significant changes to the Company's internal controls over financial reporting during the year ended December 31, 2025. The CEO and the CFO have evaluated the effectiveness of Kelt's internal controls over financial reporting as at December 31, 2025 and have concluded that such internal controls over financial reporting are effective. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

BUSINESS RISKS

The Company is exposed to various operational and financial risks inherent in the exploration, development, production and marketing of crude oil, NGLs and natural gas liquids. These inherent risks include, but are not limited to, the following:

- Reservoir quality and the uncertainty of reserves estimates;
- Volatility in the prevailing prices of crude oil, NGLs and natural gas;
- Global geopolitical conflict;
- Inflation and its impact on the cost of services and capital projects;
- The actions of OPEC+ on global oil supply and its impact on price;
- Regulatory risk related to the approval for exploration and development activities, which can add to costs or cause delays in projects;
- Environmental impact risk associated with exploration and development activities, including GHG emissions;
- Shifts in demand as global energy markets transition to a lower carbon-based economy.
- Future legislative and regulatory developments related to environmental regulation;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- The ability to find, produce and replace reserves at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, asset retirement obligations, lending capacity and depletion rates;
- Access to labor, equipment and services to complete projects in a timely and cost efficient manner;
- Operating hazards inherent in the exploration, development, production and sale of crude oil and natural gas;
- Credit risk related to non-payment for sales contracts or other counterparties;
- Interest rate risk associated with the Company's cost to borrow and ability to secure financing on commercially acceptable terms;
- Foreign exchange risk as commodity sales are predominantly based on US dollar denominated benchmarks;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;

- Increasing carbon tax and changing royalty regimes;
- The ability to secure adequate transportation for products which could be affected by pipeline and storage constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- Potential limitations on the volumes of water required for completion activities due to drought, conditions of low river flow, government restrictions or other factors;
- The access to markets for the Company's products;
- The scope and duration of export tariffs, export restrictions, or import tariffs on commodities that Kelt sells, or products that Kelt uses in its supply chains; and
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations.

Indigenous Claims

Opposition by Indigenous groups to the conduct of the Corporation's operations, development or exploratory activities in any of the jurisdictions in which the Corporation conducts business may negatively impact the Corporation in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Corporation's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. It is possible that lands on which the Corporation operates are, or could in the future become, subject to Indigenous and treaty rights claims (including Indigenous title claims). Any such claims could have a material adverse impact on the Corporation's ability to operate on such lands when the Corporation otherwise intends to or at all, which could in turn have a material adverse impact on the Corporation's financial condition, results of operations and/or growth plans.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

For example, regulatory authorities in British Columbia ceased granting approvals, and, in some cases, revoked existing approvals, for, among other things crude oil and natural gas activities relating to drilling, completions, testing, production, and transportation infrastructure following a British Columbia Supreme Court decision that the cumulative impacts of government-sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Following that decision, the Government of British Columbia signed an implementation agreement with that First Nations group to address cumulative effects of development on that group's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. These measures, which are expected to form the basis of similar arrangements with other First Nations groups in British Columbia, are expected to remain in place while a long-term cumulative effects management regime is implemented. While the Corporation believes that the regulatory authorities will resume granting and reinstate approvals for oil and natural gas activities on time frames and terms and conditions consistent with past practice, the long-term impacts of, and associated risks with the decision and arrangements with First Nations groups to address the cumulative effects of development on claimed lands on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to federal, provincial and municipal laws and regulations. Environmental legislation provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Kelt to incur costs to remedy such discharge. Kelt employs an environmental management system to manage these risks through a set of processes and practices to collect, monitor and report on the environmental impact of its operations.

No assurance can be given that the application of environmental laws to the business and operations of Kelt will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Kelt's financial condition, results of operations or prospects.

Climate Change Risks

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The federal and provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and reducing carbon emissions. This legislation along with taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with the Corporation's counterparts who operate in jurisdictions where there are less costly carbon regulations. Currently enacted carbon pricing costs are included in the Company's report on its oil and gas reserves.

Adverse impacts to the Corporation's business as a result of comprehensive carbon emission legislation or regulation applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: (i) increased compliance costs; (ii) permitting delays; (iii) substantial costs to reduce emissions or generate or purchase emission credits or allowances; and (iv) reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations.

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Climate change is expected to increase the frequency of severe weather conditions, including high winds, heavy rainfall, extreme temperatures, flooding and wildfires, which may result in damage to the Corporation's assets, disruptions in operations or transportation interruptions which may lead to increased capital expenditures or reduced revenues.

Cybersecurity

The Company has implemented cyber security protocols and procedures to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems. To manage this risk, the Company maintains a system of internal controls and purchases insurance coverage against general risks associated with cybersecurity. During the year ended December 31, 2025, the Company has not experienced a cybersecurity breach that had a material impact on the business.

Artificial Intelligence

The Corporation's information technology systems may incorporate the use of artificial intelligence ("AI") and development of such capabilities remain ongoing. As with new innovations, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Corporation's business. AI algorithms and

training methodologies may be flawed. The use of AI to support business operations of the Corporation, its partners, vendors, suppliers, contractors, or others carries inherent risks related to data privacy and cybersecurity, such as intended, unintended, or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support. Dependence on AI without adequate safeguards to make certain business decisions may introduce additional operational vulnerabilities, by producing inaccurate outcomes based on flaws or deficiencies in the underlying data or other unintended results. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to license, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remains uncertain, and the Corporation's obligation to comply with such laws could entail significant costs, negatively affect the Corporation's business or limit the Corporation's ability to incorporate certain AI capabilities into the Corporation's operations.

Risk Mitigation

The Company uses a variety of means to help mitigate or minimize these risks. The Company maintains a comprehensive insurance program to reduce risk. Operational control is enhanced by focusing on large core areas with high working interests and operatorship of drilling and completion operations. Product mix is diversified between natural gas, NGLs and oil which reduces price risk in certain market conditions. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by primarily entering into agreements with counterparties that are investment grade financial institutions, and reviews its counterparties on an on-going basis.

Tariffs and Trade Agreements

Since February 2025, multiple tariff measures between the United States, Canada have been threatened, implemented and subsequently adjusted, including with respect to the 10% U.S. tariffs on energy resources and critical minerals from Canada, which have subsequently paused since its announcement. The eventuality, timing and scope of potential U.S. tariffs, and the ultimate impact of these tariffs on the Canadian oil and gas industry, including Kelt's business, remain difficult to predict. However, should a 10% tariff on Canadian energy resources be imposed, it would significantly undermine the competitiveness of Canadian crude oil and natural gas exports to the U.S., which remains the primary export market for Western Canadian producers. Furthermore, such a tariff may reduce demand for Canadian oil and gas and lower realized commodity prices which could negatively impact Kelt's revenues and profitability.

Additionally, market uncertainty surrounding U.S.-Canada trade relations and the potential for further trade restrictions could affect Kelt's ability to raise capital. There is no assurance that trade tensions between Canada and the U.S. will be resolved favorably or that additional tariffs or trade barriers will not be introduced in the future. Any prolonged or escalated trade dispute could have a material adverse effect on Kelt's business, financial condition, and results of operations.

Recent developments in U.S.-Canada trade relations, including the proposed imposition of a 10% U.S. tariff on Canadian energy resources (including broader trade tensions between Canada and the U.S.), have increased uncertainty regarding the stability of the USMCA and the potential for future renegotiation or unilateral trade actions. In light of the evolving nature of U.S.-Canada trade relations and the potential for policy shifts, there is no assurance that the current trade framework will remain in place or that future negotiations will result in favorable terms for the Canadian energy sector. Furthermore, a renegotiation of USMCA which is anticipated to begin in July 2026 which could result in terms that are unfavorable to Canadian energy exports could potentially result in increased tariffs, quotas, or regulatory barriers, in turn reducing market access which could negatively to affect Kelt's business.

A more detailed description of the Company's risks is included in the Annual Information Form as at December 31,

2025, dated March 11, 2026 which can be found at www.sedarplus.ca.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A contains certain non-GAAP financial measures and other specified financial measures, as described below, which do not have standardized meanings prescribed by GAAP and do not have standardized meanings under the applicable securities legislation. As these non-GAAP, and other specified financial measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

NON-GAAP FINANCIAL MEASURES

P&NG sales after cost of purchases

Throughout this MD&A, reference is made to "P&NG sales" and "P&NG sales after cost of purchases". P&NG sales is as reported in the consolidated financial statements in accordance with IFRS and is before realized gains or losses on derivative financial instruments. P&NG sales after cost of purchases includes P&NG sales (in accordance with IFRS), net of the cost of third-party volumes purchases. P&NG sales after cost of purchases are used by management to assess the Company's sales from its core operations, which the Company believes may be a better indicator of historical and future performance.

See the "Petroleum and Natural Gas Sales" section of this MD&A which provides a reconciliation of "P&NG sales after cost of purchases to P&NG sales.

Net realized price

Net realized price is a non-GAAP measure and is calculated by dividing the Company's P&NG sales after cost of purchases by the Company's production and reflects Kelt's realized selling prices plus the net benefit of oil blending and third-party natural gas sales. In addition to using its own production, the Company may purchase butane and crude oil from third parties for use in its blending operations, with the objective of selling the blended oil product at a premium. Marketing revenue from the sale of third-party volumes is included in P&NG sales as reported in the Consolidated Statement of Net Income and Comprehensive Net Income in accordance with IFRS. Given the Company's per unit operating statistics disclosed throughout this MD&A are calculated based on Kelt's production volumes, and excludes the sale of third-party marketing volumes, management believes that disclosing its net realized prices based on P&NG sales after cost of purchases is more appropriate and useful, because the cost of third-party volumes purchased to generate the incremental marketing revenue has been deducted.

Combined net realized prices referenced throughout this MD&A are before derivative financial instruments, except as otherwise indicated as being after derivative financial instruments.

See the "Petroleum and Natural Gas Sales" section of this MD&A which provides a reconciliation of the net realized price to P&NG sales, which is a GAAP measure.

Operating income and operating netback

Operating income is a non-GAAP measure calculated by deducting royalties, production expenses and transportation expenses from petroleum and natural gas sales, net of the cost of purchases and after realized gains or losses on derivative financial instruments. The Company also presents operating income on a per BOE basis, referred to as "operating netback" or "operating income per BOE", which allows management to better analyze performance against prior periods, on a comparable basis, and is a key industry performance measure of operational efficiency.

See the "Adjusted Funds from Operations" section of this MD&A which provides a reconciliation of the operating income and operating netback from P&NG sales, which is a GAAP measure.

Capital expenditures

"Capital expenditures, before A&D" and "Capital expenditures, net of A&D" are measures the Company uses to monitor its investment in exploration and evaluation, investment in property plant and equipment, and net investment in acquisition and disposition activities. The most directly comparable GAAP measure is "Cash used in investing

activities", and is calculated as follows:

	Three months ended December 31		Year ended December 31	
(CA$ thousands, except as otherwise indicated)	**2025**	2024	**2025**	2024
Cash used in investing activities	**59,280**	112,062	**340,570**	336,569
Change in non-cash investing working capital	**(16,474)**	(15,016)	**(12,265)**	(3,422)
Capital expenditures, net of A&D	**42,806**	97,046	**328,305**	333,147
Property acquisitions [(1)]	**96**	(3,400)	**56**	(4,173)
Property dispositions [(1)]	**175**	-	**222**	-
Capital expenditures, before A&D	**43,077**	93,646	**328,583**	328,974

(1) Property acquisitions and property dispositions for the year ended December 31, 2025 includes $0.3 million of non-cash consideration and for the year ended December 31, 2024 includes $0.6 million of non-cash consideration.

Adjusted earnings before interest and taxes

Kelt calculates adjusted earnings before interest and taxes ("EBIT") as net income and comprehensive income plus financing, less accretion of decommissioning obligations, plus deferred income tax expense. Kelt uses adjusted EBIT as a measure of long-term operating performance and as a component in the calculation for return on average capital employed ("ROACE"). The following table contains a reconciliation of adjusted EBIT to the most directly comparable GAAP measure, net income and comprehensive income.

(CA$ thousands, except as otherwise indicated)	**December 31, 2025**	December 31, 2024	December 31, 2023
Net income and comprehensive income	**63,058**	45,423	85,974
Financing expenses	**14,594**	6,756	4,190
Accretion of decommissioning obligations	**(3,264)**	(3,082)	(2,880)
Deferred income tax expense	**20,933**	17,733	28,503
Adjusted EBIT	**95,321**	66,830	115,787

Average capital employed

Kelt calculates average capital employed as the total of net debt plus the short and long term lease obligations and shareholders equity. Kelt uses average capital employed as a measure of long-term capital management and operating performance, and as a component in the calculation for ROACE. The table below provides a reconciliation of average capital employed to the most directly comparable GAAP measures of shareholders equity.

(CA$ thousands, except as otherwise indicated)	**December 31, 2025**	December 31, 2024	December 31, 2023
Net debt – beginning of period	**124,883**	12,997	9,789
Current portion of lease obligations	**1,655**	1,125	505
Long-term portion of lease obligations	**419**	332	543
Shareholders' equity - beginning of period	**1,063,004**	1,003,663	901,424
Opening capital employed (A)	**1,189,961**	1,018,117	912,261
Net debt – end of period	**189,703**	124,883	12,997
Current portion of lease obligations	**633**	1,655	1,125
Long-term portion of lease obligations	**385**	419	332
Shareholders' equity - end of period	**1,139,639**	1,063,004	1,003,663
Closing capital employed (B)	**1,330,360**	1,189,961	1,018,117
Average capital employed (A+B)/2	**1,260,161**	1,104,039	965,189

Return on average capital employed

Kelt calculates ROACE, expressed as a percentage, as adjusted EBIT divided by the average capital employed. The components adjusted EBIT and average capital employed are non-GAAP financial measures. Kelt uses ROACE as a measure of long-term financial performance and as a component of the Company's annual compensation plan.

(CA$ thousands, except as otherwise indicated)	**Three-year Average**	**December 31, 2025**	December 31, 2024	December 31, 2023
Adjusted EBIT		**95,321**	66,830	115,787
Average capital employed		**1,260,161**	1,104,039	965,189
ROACE (%)	**9%**	**8%**	6%	12%

CAPITAL MANAGEMENT MEASURES

Funds from operations and adjusted funds from operations

Management considers funds from operations and adjusted funds from operations as a key capital management measure as it demonstrates the Company's ability to meet its financial obligations and cash flow available to fund its capital program. Funds from operations and adjusted funds from operations are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities. The most comparable GAAP measure is "Cash provided by operating activities". Funds from operations and adjusted funds from operations are calculated as follows:

	Three months ended December 31		Year ended December 31	
(CA$ thousands, except as otherwise indicated)	**2025**	2024	**2025**	2024
Cash provided by operating activities	**62,804**	48,067	**264,256**	209,145
Change in non-cash working capital	**12,614**	19,471	**(6,079)**	7,797
Funds from operations	**75,418**	67,538	**258,177**	216,942
Settlement of decommissioning obligations	**1,399**	1,868	**3,348**	5,036
Adjusted funds from operations	**76,817**	69,406	**261,525**	221,978

Net debt and net debt to adjusted funds from operations ratio

Management considers net debt and net debt to adjusted funds from operations ratio as key capital management measures to assess the Company's liquidity at a point in time and to monitor its capital structure and short-term financing requirements. The "net debt to adjusted funds from operations ratio" is also indicative of the "net debt to cash flow ratio" calculation used to determine the applicable margin for a quarter under the Company's Credit Facility agreement (though the calculation may not always be a precise match, it is representative).

"Net debt" is equal to bank debt, accounts payable and accrued liabilities, net of cash and cash equivalents, accounts receivables and accrued sales and prepaid expenses and deposits. The Company believes that using a "Net debt" non-GAAP measure, which excludes non-cash derivative financial instruments, non-cash lease liabilities, and non-cash decommissioning obligations, provides investors with more useful information to understand the Company's cash liquidity risk.

See the "Capital Resources and Liquidity" section of this MD&A for calculation of the Net debt and net debt to adjusted funds from operations ratio.

SUPPLEMENTARY FINANICAL MEASURES

"Production per common share" is calculated by dividing total production by the basic weighted average number of common shares outstanding, as determined in accordance with IFRS.

P&NG sales, cost of purchases, gain (loss) on financial instruments, royalties, production expenses, transportation expenses, financing expenses, gross and net G&A expenses, realized loss (gain) on foreign exchange, other income

(expense), share based compensation expense, and depletion and depreciation expense on a $/BOE basis is calculated by dividing the amounts by the Company's total production over the period.

Adjusted funds from operations per share (basic and diluted), and net income and comprehensive net income per share (basic and diluted) is calculated by dividing the amounts by the basic weighted average common shares outstanding.

Net asset value

"Net asset value" is calculated by adding the present value of proved plus probable petroleum and natural gas reserves discounted at 10% before-tax (as estimated by McDaniel effective December 31, 2025), undeveloped land value, proceeds from exercise of stock options, and net bank debt. "Net asset value per common share" is calculated by dividing the "Net asset value" by the diluted number of common shares outstanding. The calculation of proceeds from exercise of stock options and the diluted number of common shares outstanding only include stock options that are "in-the-money" based on the closing price of Kelt common shares as at the calculation date. Management believes that the "Net asset value" provides a useful measure to analyze the comparative change in the Company's estimated value on a normalized basis.

See the "Net asset value" section of this MD&A which provides a reconciliation of the net asset value to Kelt's Present value of 2P P&NG reserves, discounted at 10% before-tax.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

The information set out herein is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Kelt's reasonable expectations as to the anticipated results of its proposed business activities for the calendar year 2026. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Certain information with respect to Kelt contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, many of which are beyond Kelt's control, including the impact of general economic conditions, the scope and duration of export tariffs, export restrictions, or import tariffs on commodities that Kelt sells, or products that Kelt uses in its supply chains, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital.

Any forward-looking information or financial outlook set out herein does not include any potential impact of cross border tariffs, additional trade-related regulations or future negotiations that may take place between the United States and Canada.

As a result, Kelt's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur.

In addition, the reader is cautioned that historical results are not necessarily indicative of future performance. The forward-looking statements contained herein are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves, and the future net revenue attributed to such reserves, including many factors beyond the control of Kelt. The reserves and associated future net revenue information set forth in this MD&A are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at

different times, may vary.

Kelt's actual production, revenue, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by the Corporation's independent qualified reserves evaluators represent the fair market value of those reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. Actual oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein, and variances could be material.

With respect to the disclosure of reserves contained herein relating to portions of Kelt's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Unless otherwise stated all references to "reserves" are to Kelt's gross company reserves before deduction of royalties and without including and royalty interests of Kelt. It should not be assumed that the undiscounted or discounted net present value of the Company's reserves, as determined by McDaniel, represents the fair value of those reserve estimates.

This MD&A contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "potentially" and similar expressions are intended to identify forward-looking information or statements. In particular, this MD&A contains forward-looking statements pertaining to the following: Kelt's expected price realizations and future commodity prices; its expected oil and NGLs weighting; the start-up date of the postponed wells; the cost and timing of future capital expenditures and expected results; the expected timing of wells bring brought on-production; the expected timing of production additions from capital expenditures; the ability to show significant production growth; the expected reductions in drill and complete costs; the expected timing and processing capacity from the start-up of a third party facility; the expected timing of when the Company shoots its 3-D seismic program; and the Company's expected future financial position and operating results.

References herein to the IP30 and IP365 production rates are useful in confirming the presence of hydrocarbons, however the production rates are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. Readers are cautioned not to place reliance on such rates in calculating aggregate production for the assets for which such rates are provided.

Statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserves may be greater than or less than the estimates provided herein.

Although Kelt 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 Kelt cannot give any assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general, 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; failure to obtain necessary regulatory approvals for planned operations; health, safety and environmental risks; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; volatility of commodity prices, currency exchange rate fluctuations; imprecision of reserve estimates; as well as general economic conditions, stock market volatility; the ability to access sufficient water or other fluids needed for completion operations; and the ability to access sufficient capital. We caution that the foregoing list of risks and uncertainties is not exhaustive.

ADDITIONAL INFORMATION

Additional information relating to Kelt, including the Company's Annual Information Form ("AIF") dated March 11, 2026 is filed on SEDAR+ and can be viewed on their website at www.sedarplus.ca. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President and Chief Financial Officer at Kelt Exploration Ltd., Suite 300, 311 Sixth Avenue SW, Calgary, Alberta, Canada, T2P 3H2. Further information relating to Kelt is also available on its website at www.keltexploration.com.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements of Kelt Exploration Ltd. (the "Company") are the responsibility of management. The consolidated financial statements have been prepared by management in Canadian dollars in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS Accounting Standards") and include certain estimates that reflect management's best judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances.

Management has the overall responsibility for internal controls and maintains a system of internal controls over financial reporting that provides reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of non-management directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board of Directors has approved the consolidated financial statements and authorized them for issuance to shareholders.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by the shareholders of the Company, to provide an independent audit opinion on the Company's consolidated financial statements. Their report, contained herein, outlines the nature of their audit and expresses an unqualified opinion on the consolidated financial statements.

[signed]

David J. Wilson
President and Chief Executive Officer
March 11, 2026

[signed]

Sadiq H. Lalani
Vice President and Chief Financial Officer
March 11, 2026

Independent auditor's report

To the Shareholders of Kelt Exploration Ltd.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Kelt Exploration Ltd. and its subsidiary (together, the company) as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards).

What we have audited

The company's consolidated financial statements comprise:

- the consolidated statements of financial position as at December 31, 2025 and 2024;
- the consolidated statements of net income and comprehensive net income for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, comprising material accounting policy information and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
Suncor Energy Centre, 111 5th Avenue South West, Suite 2900
Calgary, Alberta, Canada T2P 5L3
T.: +1 403 509 7500, F.: +1 403 781 1825
Fax to mail: ca_calgary_main_fax@pwc.com

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

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, 2025. 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.

Key audit matter	How our audit addressed the key audit matter
The impact of crude oil and natural gas proved reserves on net development and production (D&P) assets Refer to note 2(c) – Significant judgments and estimates, note 3 – Material accounting policies and note 5 – Property, plant and equipment to the consolidated financial statements. The company has $1,496 million of net D&P assets as at December 31, 2025. Depletion and depreciation expense for the D&P assets was $182 million for the year then ended. D&P assets are depleted using the unit of production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. The significant assumptions used by management to determine the proved reserves of the company's D&P assets include production forecasts, future production costs, forecasted commodity prices and future development costs. The proved reserves are determined by the company's independent qualified reserve evaluators (management's experts). We considered this a key audit matter due to (i) the significant judgments made by management, including the use of management's experts, when estimating the proved reserves; and (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the significant assumptions.	Our approach to addressing the matter included the following procedures, among others: • Tested how management determined the proved reserves, which included the following: – The work of management's experts was used in performing the procedures to evaluate the reasonableness of the proved reserves. As a basis for using this work, the competence, capabilities and objectivity of management's experts was evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and an evaluation of their findings. – Evaluated the reasonableness of significant assumptions used, including production forecasts, future production costs and future development costs by considering the current and past performance and whether these assumptions were consistent with evidence obtained in other areas of the audit, as applicable. – Evaluated the reasonableness of forecasted commodity prices by comparing them to third party industry forecasts. • Recalculated the unit of production rates used to calculate depletion and depreciation expense for the D&P assets.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated 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 consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

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

In preparing the consolidated 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 consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated 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 generally accepted auditing standards 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 consolidated financial statements.

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

- Identify and assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes 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 Alexandra Arnell.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta

March 11, 2026

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
AS AT DECEMBER 31, 2025 AND DECEMBER 31, 2024

(CA$ thousands)	[Notes]	**December 31, 2025**	December 31, 2024
ASSETS			
Current assets			
Cash and cash equivalents		**90**	228
Accounts receivable and accrued sales	[10]	**64,195**	60,236
Prepaid expenses and deposits		**3,919**	4,109
Derivative financial instruments	[10]	**17,048**	6,709
Total current assets		**85,252**	71,282
Exploration and evaluation assets	[4]	**18,140**	18,092
Property, plant and equipment	[5]	**1,497,123**	1,361,305
Total assets		**1,600,515**	1,450,679
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities	[10]	**78,046**	80,463
Derivative financial instruments	[10]	**1,033**	7,936
Decommissioning obligations	[7]	**5,463**	3,552
Lease liability	[8]	**633**	1,655
Total current liabilities		**85,175**	93,606
Bank debt	[6]	**179,861**	108,993
Decommissioning obligations	[7]	**87,288**	97,423
Lease liability	[8]	**385**	419
Deferred income tax liability	[11]	**108,167**	87,234
Total liabilities		**460,876**	387,675
SHAREHOLDERS' EQUITY			
Shareholders' capital	[9]	**1,195,874**	1,184,065
Contributed surplus and reserve		**(4,924)**	(6,692)
Deficit		**(51,311)**	(114,369)
Total shareholders' equity		**1,139,639**	1,063,004
Total liabilities and shareholders' equity		**1,600,515**	1,450,679
Commitments	[14]		

The accompanying notes form an integral part of these consolidated financial statements.

On behalf of the Board of Directors:

[signed] — David J. Wilson, Director

[signed] — Ray Kwan, Director

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENTS OF NET INCOME AND COMPREHENSIVE NET INCOME
FOR THE YEARS ENDED DECEMBER 31, 2025 AND DECEMBER 31, 2024

		Year ended December 31	
(CA$ thousands, except per share amounts)	[Notes]	**2025**	2024
Revenue			
Petroleum and natural gas sales	[12]	**513,085**	468,432
Royalties		**(46,097)**	(54,737)
		466,988	413,695
Expenses			
Production		**140,376**	121,355
Transportation		**50,507**	42,625
Cost of purchases		**17,263**	16,365
Financing	[13]	**14,594**	6,756
General and administrative	[15]	**13,493**	12,272
Share based compensation	[9]	**7,813**	8,846
Exploration and evaluation	[4]	**157**	214
Depletion and depreciation	[5]	**183,571**	141,494
		427,774	349,927
Gain (loss) on derivative financial instruments	[10]	**44,984**	(933)
Gain (loss) on foreign exchange		**(277)**	204
Gain on sale of assets		**165**	-
Other income (expenses)		**(95)**	117
Net income before taxes		**83,991**	63,156
Deferred income tax expense	[11]	**(20,933)**	(17,733)
Net income and comprehensive income		**63,058**	45,423
Net income per common share			
Basic	[9]	**0.32**	0.23
Diluted	[9]	**0.31**	0.23

The accompanying notes form an integral part of these consolidated financial statements.

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2025 AND DECEMBER 31, 2024

		Shareholders' capital		Contributed		Total
(CA$ thousands)	[Notes]	Number of Shares (000s)	Amount ($ thousands)	surplus and reserve	Retained earnings (deficit)	shareholders' equity
Balance at December 31, 2023		194,506	1,175,465	(12,010)	(159,792)	1,003,663
Net income and comprehensive income		-	-	-	45,423	45,423
Exercise of stock options	[9]	1,836	7,175	(2,103)	-	5,072
Vesting of restricted share units	[9]	414	1,425	(1,425)	-	-
Share based compensation	[9]	-	-	8,846	-	8,846
Balance at December 31, 2024		196,756	1,184,065	(6,692)	(114,369)	1,063,004
Net income and comprehensive income		-	-	-	63,058	63,058
Exercise of stock options	[9]	2,366	8,552	(2,788)	-	5,764
Vesting of restricted share units	[9]	683	3,257	(3,257)	-	-
Share based compensation	[9]	-	-	7,813	-	7,813
Balance at December 31, 2025		**199,805**	**1,195,874**	**(4,924)**	**(51,311)**	**1,139,639**

The accompanying notes form an integral part of these consolidated financial statements.

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2025 AND DECEMBER 31, 2024

		Year ended December 31	
(CA$ thousands)	[Notes]	**2025**	2024
Operating activities			
Net income and comprehensive income		**63,058**	45,423
Items not affecting cash:			
Accretion of decommissioning obligations	[13]	**3,264**	3,082
Share based compensation	[9]	**7,813**	8,846
Exploration and evaluation	[4]	**157**	214
Depletion and depreciation	[5]	**183,571**	141,494
Unrealized (gain) loss on derivative financial instruments	[10]	**(17,242)**	5,186
Other expenses		**136**	-
Gain on sale of assets		**(165)**	-
Deferred income tax expense	[11]	**20,933**	17,733
Settlement of decommissioning obligations	[7]	**(3,348)**	(5,036)
Change in non-cash operating working capital	[16]	**6,079**	(7,797)
Cash provided by operating activities		**264,256**	209,145
Financing activities			
Increase in bank debt	[6]	**70,868**	108,993
Proceeds on exercise of stock options	[9]	**5,764**	5,072
Repayment of lease liability principal	[8]	**(456)**	(753)
Cash provided by financing activities		**76,176**	113,312
Investing activities			
Exploration and evaluation assets	[4]	**(15,176)**	(2,961)
Property, plant and equipment	[5]	**(313,407)**	(326,013)
Property acquisitions		**56**	(4,173)
Property dispositions		**222**	-
Change in non-cash investing working capital	[16]	**(12,265)**	(3,422)
Cash used in investing activities		**(340,570)**	(336,569)
Net change in cash and cash equivalents		**(138)**	(14,112)
Cash and cash equivalents, beginning of year		**228**	14,340
Cash and cash equivalents, end of year		**90**	228

The accompanying notes form an integral part of these consolidated financial statements.

(All tabular amounts in thousands of Canadian dollars, except as otherwise indicated)

1. DESCRIPTION OF THE BUSINESS

Kelt Exploration Ltd. ("Kelt" or the "Company") is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources in northwestern Alberta and northeastern British Columbia. The Company's British Columbia assets are operated by Kelt Exploration (LNG) Ltd. ("Kelt LNG"), a wholly owned subsidiary of Kelt. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "KEL".

The head office of Kelt is located at Suite 300, 311 - 6th Avenue S.W., Calgary, Alberta T2P 3H2.

2. BASIS OF PRESENTATION

The Company's Board of Directors approved and authorized these consolidated financial statements on March 11, 2026.

a) Statement of compliance

The Company prepares its consolidated financial statements (the "financial statements") in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

b) Basis of measurement

All references to dollar amounts in these financial statements and related notes are thousands of Canadian dollars, unless otherwise indicated.

The financial statements have been prepared on a historical cost basis, except for certain financial instruments which are recorded at fair value. The methods used to measure fair values are described in note 10 of these financial statements.

c) Significant judgments and estimates

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ materially from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are reviewed and for any future years affected. Significant judgments, estimates and assumptions made by management in these financial statements are discussed below.

Depletion, depreciation and reserves

The net carrying value of property, plant, and equipment ("PP&E") is depleted using total proved reserves and future development costs, as determined by the Company's independent qualified reserve evaluators. This evaluation of proved and proved plus probable reserves is prepared in accordance with the reserves definitions as set up by the Canadian Securities Administrators in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook ("COGEH"). Future profit (loss) can be affected as a result of the methodology of depleting the net carrying value of property, plant and equipment.

Reserves (proved and probable) are also used in measuring the fair value less costs of disposal ("FVLCD") of property, plant and equipment for impairment calculations and for determining the fair value of PP&E acquired in a business combination. The reserve estimates are based on production forecasts, future production costs, forecasted commodity prices and future development costs. Reserves also impact the assessment of the commercial viability and technical feasibility of an exploration project which impacts the decision to transfer exploration and evaluation assets ("E&E") to

PP&E.

Although reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation can be impacted by subjective decisions, new geological or production information and a changing environment. In addition, revisions to reserve estimates can arise from changes in forecast oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

Exploration and evaluation assets

Judgment is required to determine the level at which E&E is assessed for impairment. The carrying value of E&E assets is assessed for overall impairment at the operating segment level and on a specific identification basis prior to transferring E&E assets to PP&E. The decision to transfer assets from E&E to PP&E requires judgment as it is based on whether the E&E investments have a sufficient amount of economically recoverable reserves to ensure a projects technical feasibility and commercial viability.

E&E assets remain capitalized as long as sufficient progress is being made by the Company in assessing the technical feasibility and commercial viability of these assets. Changes to project economics, forecasted commodity prices, expected capital investment costs and production costs are important factors considered in assessing the technically feasible and commercially viable of these assets.

Determination of Cash Generating Units ("CGUs")

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality. As at December 31, 2025, the Company has one CGU for its assets located in the province of British Columbia and one CGU for its assets located in the province of Alberta.

Impairment of non-financial assets

Significant judgment is required to assess non-financial assets, namely E&E and PP&E, for indicators of impairments. Management must first determine whether indicators of impairment exist that suggest the carrying value may not be recoverable through the asset's continued use or sale.

Significant assumptions used to estimate the recoverable amount of PP&E in the impairment test include proved and probable reserve volumes, commodity price forecasts, future production volumes, future production costs, future development capital expenditures and the discount rate.

Management calculates the recoverable amount of each CGU based on its FVLCD, using an after-tax discounted cash flow analysis derived from proved plus probable reserves. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty as discussed above and are subject to variability due to changes in forecasted commodity prices. In addition, the present value of forecast future cash flows is highly sensitive to the discount rate. Judgment is required to determine an appropriate discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

Decommissioning obligations

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and infrastructure. In most instances, dismantling of assets and remediation occurs many years into the future. The future value of the decommissioning obligation, and the related asset, can increase or decrease in response to many factors including changes to legal requirements, the emergence of new restoration techniques, experience at other production sites, changes to the risk-free discount rate and changes to inflation. The expected timing and amount of expenditure may be adjusted in response to revisions in reserves or changes in laws and regulations and could be impacted by the rate the markets transition to a lower carbon-based economy. Judgments include the most appropriate discount rate to use, which management has determined to be a risk-free rate. Key assumptions are disclosed in note 7 of these financial statements.

Kelt estimates abandonment and reclamation costs based on a combination of publicly available industry benchmarks and internal site specific information. For producing wells and facilities, the expected timing of settlement is estimated

based on the proved plus probable period to abandonment for each depletable area, as per the independent reserve report. For non-producing wells which are not currently under a planned abandonment or reclamation program, the expected timing of settlement is estimated to be between three and ten years. Non-producing wells under a planned abandonment or reclamation program are not discounted and are included under current liabilities.

Deferred income taxes

The liability method is used for calculating deferred income taxes. Tax interpretations, regulations and legislation in the jurisdictions in which the Company operates are subject to change. As such, deferred income taxes are subject to measurement uncertainty.

Share based compensation

The fair value method of accounting is used for its long-term incentive plans, which include an Incentive Stock Option Plan, a Restricted Share Unit Plan, and a Performance Share Unit Plan. Judgments include which valuation model is most appropriate for the grant of the award to estimate its fair value. Estimates and assumptions are then used in the valuation model to determine fair value.

For stock options, the Black-Scholes option pricing model is used, which requires that management make assumptions for the expected life of the option, the anticipated volatility of the share price over the life of the option, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. These assumptions are disclosed in note 9 of these financial statements.

The fair value of restricted share units is estimated based on the closing price on the TSX on the date of the grant. Judgment is also required to estimate the rate of forfeiture, or number of restricted share units that will ultimately vest.

The fair value of performance share units is estimated based on the closing price on the TSX on the date of the grant and relevant market vesting conditions. Judgment is also required to estimate the number of performance share units that will ultimately vest, taking into consideration the non-market vesting conditions applicable to each performance share unit.

3. MATERIAL ACCOUNTING POLICIES

New Accounting Policies

The IASB issued amendments to IAS 1 "Presentation of financial statements" which is effective for annual periods beginning on or after January 1, 2024. The amendments clarified how an entity classifies debt and other financial liabilities as current or non-current in certain circumstances. These amendments to IAS 1 did not have any impact on the Company’s financial statements.

In April 2024, the IASB issued IFRS 18 'Presentation and Disclosure in Financial Statements' which will replace IAS 1 'Presentation of Financial Statements'. The standard introduces a new defined structure to the Consolidated Statements of Net Income and Comprehensive Net Income with new categories for income and expenses and new totals and subtotals. In addition, there are additional disclosures around management defined performance measures and additional requirements regarding the aggregation and disaggregation of certain information. IFRS 18 is effective January 1, 2027, and are required to be adopted retrospectively with early adoption permitted. The Company is currently assessing the impact of IFRS 18 on the Company's consolidated financial statements.

In May 2024, the IASB issued amendments IFRS 9 'Financial Instruments' and IFRS 7 'Financial Instruments: Disclosures' to clarify the date of recognition and derecognition of financial assets and liabilities including the settling of financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. These amendments are effective January 1, 2026, and are required to be adopted retrospectively with early adoption permitted. The Company has determined that there will not be material impacts to the Company's consolidated financial statements.

Joint interests

A portion of the Company’s exploration, development and production activities is conducted jointly with others through unincorporated joint ventures. These financial statements reflect only the Company’s proportionate interest of these

jointly controlled assets and the proportionate share of the relevant revenue and related costs.

Foreign currency translation

The financial statements are presented in Canadian dollars, which is the Company's functional and presentation currency. Transactions in U.S. dollars are initially recorded at the exchange rate in effect at the time of the transactions. Monetary assets and liabilities denominated in U.S. dollars are translated to Canadian dollars using the closing exchange rate at the Consolidated Statement of Financial Position date. The resulting exchange rate differences are included in the Consolidated Statement of Net Income and Comprehensive Net Income.

Principles of consolidation

As at December 31, 2025, the Company has one wholly-owned subsidiary, Kelt LNG. Subsidiaries are entities controlled by the Company. Control exists when there is power to govern the financial and operating policies of an entity to obtain benefits from its activities. The consolidated financial statements include the accounts of Kelt and Kelt LNG. The financial statements of Kelt LNG are prepared for the same reporting period as Kelt using uniform accounting policies. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date there is a loss of control. All intercompany balances, transactions, revenue and expenses are eliminated on consolidation.

Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and all risks and rewards of ownership have substantially transferred.

Financial assets and liabilities are offset and the net amount is reported in the Consolidated Statement of Financial Position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, financial instruments are measured at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, financial instruments are measured at amortized cost or at fair value through profit or loss ("FVTPL") depending on the purpose for which the instruments were acquired.

ii) Derivative financial instruments

The Company may use derivative financial instruments for risk management purposes. All derivatives have been classified at FVTPL. Financial instruments are included on the Consolidated Statement of Financial Position within derivative financial instruments and are classified as current or non-current based on the contractual terms specific to the instrument. Gains and losses on re-measurement of derivatives are included in profit or loss in the period in which they arise.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related. Gains and losses on re-measurement of embedded derivatives are included in profit or loss in the period in which they arise.

Physical commodity contracts are entered into and held for the purpose of receipt or delivery of non-financial items. These contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position, unless it is determined that an embedded derivative exists within the contract. Realized gains or losses from physically settled commodities sales contracts are recognized in petroleum and natural gas sales as the contracts are settled.

Exploration and evaluation assets and property, plant and equipment

i) Recognition and measurement

All costs directly associated with the exploration and evaluation of petroleum and natural gas reserves are initially capitalized. Exploration and evaluation costs include unproved property acquisition costs such as undeveloped land and mineral leases, geological and geophysical costs, and costs associated with exploratory drilling and appraisals. Such costs are not subject to depletion or depreciation until they are reclassified from E&E to PP&E.

The costs are accumulated by exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability is considered to be achieved when a sufficient amount of economically recoverable reserves relative to the estimated potential resources is estimated to exist, combined with available infrastructure to support commercial development. Prior to being transferred to PP&E, E&E costs are first tested for impairment. If proved/probable reserves have not been established through exploration and evaluation activities, and there are no future plans for activity in that exploration area, then the costs are determined to be impaired and the amounts are expensed to the Consolidated Statement of Net Income and Comprehensive Net Income.

Property, plant and equipment

Property, plant, and equipment primarily consists of petroleum and natural gas development and production assets, and is measured at cost less accumulated depletion and depreciation and accumulated impairment losses. These costs include property acquisitions, development drilling, completion, gathering and infrastructure, estimated decommissioning costs and transfers from E&E.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing components of equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are expensed as incurred. Such capitalized amounts generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized.

The gain or loss from the sale of property, plant and equipment is recognized in the Consolidated Statement of Net Income and Comprehensive Net Income. In addition, agreements in which the Company cedes a portion of its working interest to a third-party are generally considered to be disposals of property, plant and equipment, potentially resulting in a gain or loss on disposition.

Exchanges of property, plant and equipment are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Unless the fair value of the asset received is more clearly evident, the cost of the acquired asset is measured at the fair value of the asset given up. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

Property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying value of the asset) is included in profit or loss in the period in which the item is derecognized.

iii) Depletion and depreciation

Development and production costs are accumulated on an area basis (“depletion units”). The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. Proved reserves and future development cost estimates are reviewed by independent reserve engineers at least annually. Where significant components of development and production (“D&P”) assets have different useful lives, they are accounted for and depreciated as separate items of property, plant and equipment.

iv) Major maintenance expenditures

The costs of major maintenance associated with turnaround activities that benefit future years of operations are capitalized and depreciated over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment of assets

Non-financial assets

The carrying value of non-financial assets, including PP&E and E&E, is reviewed on a quarterly basis to determine whether there is any indication of impairment. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or CGUs. The recoverable amount of an asset or a CGU is the greater of its value in use and its FVLCD. E&E assets are assessed for overall impairment at the operating segment level and individual E&E assets are assessed for impairment prior to transferring to PP&E.

FVLCD is defined as the amount obtainable from the sale of an asset or cash generating unit in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal. FVLCD is calculated by reference to the after-tax future cash flows expected to be derived from production of proved plus probable reserves, less estimated selling costs. The estimated after-tax future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. 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. The timing of when the global energy markets transition to a lower carbon-based economy is highly uncertain and may impact the FVLCD.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Consolidated Statement of Net Income and Comprehensive Net Income. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

Financial assets

A financial asset measured at amortized cost is assessed at each reporting date using an expected credit loss ("ECL") model to determine whether it is impaired. The simplified approach is applied to calculating the ECLs, as prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. A combination of historical and forward looking information is used to determine the appropriate loss allowance provision. ECLs are a probability-weighted estimate of all possible default events over the expected life of the financial asset which is based on credit quality since initial recognition.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

Provisions and contingencies

Provisions are recognized when there is a present obligation as a result of a past event, if it is probable that an outflow of resources will be required and if a reliable estimate can be made of the amount of the obligation. Provisions are measured based on the best estimate of discounted future cash outflows.

Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site remediation activities. An obligation is accrued for the estimated cost of site restoration and the corresponding amount is included in the cost of the assets to which the obligations relate. Decommissioning obligations are measured at the present value of the estimated expenditures required to settle the present obligation at the Consolidated Statement of Financial Position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation, changes to the expected timing of site restoration, as well as any changes in the risk-free discount rate and inflation rate. Increases in the provision due to the passage of time are recognized as a financing expense in the Consolidated Statement of Net Income and Comprehensive Net Income whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision is established.

Contingencies

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the Company. When a contingency is substantiated by confirming events, can be reliably measured and will likely result in an economic outflow, a liability is recognized in the financial statements as the best estimate required to settle the obligation. A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events, or where the amount of a present obligation cannot be measured reliably or will likely not result in an economic outflow.

Contingent assets are only disclosed when the inflow of economic benefits is probable. When the economic benefit becomes virtually certain, the asset is no longer contingent and is recognized in the financial statements.

Income taxes

Total income tax expense is composed of both current and deferred income taxes.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

The liability method is used for accounting for income taxes. Under this method, deferred income tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are allocated between income and equity depending on the nature of the account balance or transaction that gives rise to the temporary difference.

Deferred tax liabilities are recognized for taxable temporary differences. Deferred tax assets are recognized for deductible temporary differences, unused tax losses and unused tax credits only if it is probable that sufficient future taxable income will be available to utilize those temporary differences and losses and at the time of the transaction, does not give rise to equal taxable and deductible temporary differences. Such deferred tax liabilities and assets are not recognized if the temporary difference arises from goodwill or from 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 profit nor taxable income. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. The effect of a change in income tax rates on deferred tax assets and liabilities is recognized in the Consolidated Statement of Net Income and Comprehensive Net Income in the period that the change occurs. Deferred tax assets and liabilities are recorded on a non-discounted basis.

Revenue recognition

Revenue is recognized at a point in time when control of the product has been transferred to the customer and performance obligations have been satisfied. This is generally met when the customer obtains legal title to the product and physical delivery at a delivery point has taken place. Revenue is measured based on the consideration specified in the contracts with the customers. The Company has applied the practical expedient to recognize revenue in the amount to which it has the right to invoice. As such, no disclosure is included relating the transaction price allocated to any remaining unsatisfied performance obligations and when these amounts will be recognized.

Arrangements are evaluated with third parties and partners to determine if a principal or agent relationship exists. In making this evaluation, management considers if it maintains control of the product, which is indicated by the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If management determines that it does not maintain control of the product, then revenue is recognized net of fees, if any, realized by the party from the transaction.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

Share based compensation

The Company has an Incentive Stock Option Plan, a Restricted Share Unit Plan, and a Performance Share Unit Plan (collectively, the “Plans”). In April 2025, the Company discontinued the ability to issue any additional stock options under its Incentive Stock Option Plan. Stock options issued prior to April 2025 were granted to officers, directors, employees and certain consultants, which call for settlement through the issuance of new common shares. Restricted

share units (“RSUs”) and performance share units (“PSUs”) may be granted to officers, directors and employees, which call for settlement through the issuance of new common shares.

The fair value method is applied to the accounting for stock options, whereby each tranche in an award is valued separately on the grant date using the Black-Scholes option pricing model. The fair value of RSUs is calculated based on the closing price on the TSX on the date of the grant. The fair value of PSUs is estimated based on the closing price on the TSX on the date of the grant and relevant market vesting conditions. The number of PSUs that will ultimately vest is estimated, taking into consideration the non-market vesting conditions applicable to each PSU.

The total fair value associated with stock options, RSUs, and PSUs is recognized over the service period using graded vesting, as share based compensation expense with a corresponding increase to contributed surplus. An estimated forfeiture rate is applied against the total fair value on the grant date and is adjusted to reflect the actual number of options that ultimately vest each period. The consideration received on the exercise of stock options is recorded as an increase in shareholders’ capital, together with the corresponding amounts previously recognized in contributed surplus.

Earnings per share amounts

Basic net income per common share is calculated by dividing net income for the period attributable to common shareholders by the weighted average number of common shares outstanding during the period. Common shares issued as part of the consideration transferred in a business combination or common control transaction are included in the weighted average number of common shares starting from the acquisition date.

Diluted net income per common share is calculated giving effect to the potential dilution that would occur if all outstanding “in-the-money” stock options were exercised or converted to common shares. The weighted average number of common shares outstanding during the period is adjusted by the incremental number of shares calculated in accordance with the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the volume weighted average market price during the period.

4. EXPLORATION AND EVALUATION ASSETS

The following table reconciles movements of exploration and evaluation (“E&E”) assets:

	December 31, 2025	December 31, 2024
Balance, beginning of year	**18,092**	17,162
Additions	**15,176**	2,961
Transfers to property, plant and equipment	**(14,971)**	(1,817)
Exploration and evaluation expense	**(157)**	(214)
Balance, end of year	**18,140**	18,092

The Company concluded that there are no indicators of potential impairment of its E&E assets at December 31, 2025 and December 31, 2024.

5. PROPERTY, PLANT AND EQUIPMENT

The Company's property, plant and equipment ("PP&E") includes development and production ("D&P") assets, corporate assets, and right-of-use ("ROU") assets.

The following table reconciles movements of property, plant and equipment during the year:

Property, plant and equipment, at cost	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2023	2,057,993	7,908	4,617	2,070,518
Additions	324,190	1,140	1,967	327,297
Transfers from ROU assets	683	-	(683)	-
Property acquisitions	5,115	-	-	5,115
Property dispositions and derecognition	(705)	-	-	(705)
Change in decommissioning obligations	2,777	-	-	2,777
Transfers from E&E	1,817	-	-	1,817
Balance at December 31, 2024	**2,391,870**	**9,048**	**5,901**	**2,406,819**
Additions	**311,138**	**981**	**1,210**	**313,329**
Transfers from ROU assets	**1,288**	**-**	**(1,288)**	**-**
Property acquisitions	**477**	**-**	**-**	**477**
Property dispositions and derecognition [(1)]	**(470)**	**-**	**(4,544)**	**(5,014)**
Change in decommissioning obligations	**(8,260)**	**-**	**-**	**(8,260)**
Transfers from E&E	**14,971**	**-**	**-**	**14,971**
Balance at December 31, 2025	**2,711,014**	**10,029**	**1,279**	**2,722,322**

Accumulated depletion, depreciation and impairment	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2023	893,745	7,333	3,028	904,106
Depletion and depreciation expense	139,894	868	732	141,494
Property dispositions and derecognition	-	-	(86)	(86)
Balance at December 31, 2024	**1,033,639**	**8,201**	**3,674**	**1,045,514**
Depletion and depreciation expense	**181,858**	**1,207**	**506**	**183,571**
Property dispositions and derecognition [(1)]	**-**	**-**	**(3,886)**	**(3,886)**
Balance at December 31, 2025	**1,215,497**	**9,408**	**294**	**1,225,199**

Net carrying amount	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance, December 31, 2024	1,358,231	847	2,227	1,361,305
Balance, December 31, 2025	**1,495,517**	**621**	**985**	**1,497,123**

(1) In the third quarter of 2025 the Company derecognized $3.1 million of cost and accumulated depreciation related to ROU Assets where the lease term had ended.

Future capital costs required to develop proved reserves in the amount of $1,928.3 million (December 31, 2024 – 1,839.9 million) are included in the depletion calculation for development and production assets.

Based on its assessment as of December 31, 2025 and December 31, 2024, the Company determined that there were no indicators of impairment.

6. BANK DEBT

At December 31, 2025, the Company has a $300.0 million credit facility from a syndicate of financial institutions. As at December 31, 2025, $179.9 million was drawn under the credit facility. In addition to the amounts drawn, the Company had $2.4 million in letters of credit guarantees. The Credit Facility may be extended annually at Kelt's option and subject to lender approval, with a 364 day term-out period if not renewed.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount. The credit facility is subject to semi-annual redeterminations on or before June 30 and November 30 of each year. There are no financial covenants under the Credit Facility and Kelt is in compliance with all other covenants. Covenants include industry standard positive and negative covenants including reporting requirements, permitted indebtedness, permitted risk management activities, permitted encumbrances and other standard business operating covenants. Security is provided for by a demand debenture with a floating charge over all assets in the amount of $800.0 million.

Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on the prime rate plus the applicable margin. The applicable margin ranges from 175 basis points to 375 basis points depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times. Under the Credit Facility, borrowings through the use of benchmark loans are also available. Stamping fees fluctuate based on a pricing grid and range from 2.75% to 4.75%, depending upon the Net Debt to Cash Flow ratio of between less than 0.5 times and three times.

7. DECOMMISSIONING OBLIGATIONS

Decommissioning obligations arise as a result of the Company's net ownership interests in petroleum and natural gas assets including well sites, processing facilities and infrastructure. The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

	December 31, 2025	December 31, 2024
Balance, beginning of year	**100,975**	99,915
Obligations incurred	**1,770**	3,247
Obligations acquired	**261**	299
Obligations disposed	**(141)**	(62)
Obligations settled	**(3,348)**	(5,036)
Changes in discount rate	**(11,492)**	(6,954)
Revisions to estimates	**1,462**	6,484
Accretion expense	**3,264**	3,082
Balance, end of year	**92,751**	100,975
Decommissioning obligations – current	**5,463**	3,552
Decommissioning obligations – non-current	**87,288**	97,423
Key assumptions		
Risk-free rate	**3.9%**	3.3%
Inflation rate	**2.0%**	2.0%

The underlying cost estimates are derived from a combination of published industry benchmarks and site-specific information. As at December 31, 2025 the undiscounted amount of the estimated cash flows required to settle the obligation is $144.7 million (December 31, 2024 – $144.3 million) and is expected to be incurred over the next 50 years. The undiscounted amount of the estimated future cash flows required to settle the obligation is $243.0 million at December 31, 2025 (December 31, 2024 – $274.4 million). The inflated future cost estimates are discounted based on a risk-free rate to determine the carrying amounts presented in the table above. Accretion of the decommissioning obligation due to the passage of time is presented within financing expenses in the Consolidated Statements of Net Income and Comprehensive Net Income (note 13).

The table below shows the impact of a 1% increase/decrease in the risk-free rate, and of a 1% increase/decrease in the inflation rate on the Company's decommissioning obligation.

	Change in rate	Positive movement	Negative movement
Risk-free rate	+/- 1%	(16,241)	23,429
Inflation rate	+/- 1%	23,663	(16,620)

8. LEASE LIABILITY

	December 31, 2025	December 31, 2024
Balance, beginning of year	**2,074**	1,457
Additions	**1,210**	1,967
Disposals	**(1,810)**	(597)
Interest expense	**125**	167
Lease payments	**(581)**	(920)
Balance, end of year	**1,018**	2,074
Lease liability – current	**633**	1,655
Lease liability – non-current	**385**	419

Lease liabilities include commercial office space and field equipment. The weighted average discount rate for new leases entered in the period ended December 31, 2025 was 9.4% (December 31, 2024 – 8.9%). Payments under short-term leases were $11.8 million for the year ended December 31, 2025 (December 31, 2024 – $13.0 million), which primarily related to short term drilling rigs and field equipment rentals.

9. SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, each without par value.

Issued and outstanding

The following table summarizes the change in common shares issued and outstanding. There are no preferred shares issued or outstanding as of December 31, 2025 (December 31, 2024 – nil).

	Number of Shares (000s)	Amount ($ thousands)
Balance at December 31, 2023	194,506	1,175,465
Issued on exercise of stock options	1,836	5,072
Transfer from contributed surplus on exercise of stock options	-	2,103
Released upon vesting of restricted share units	414	1,425
Balance at December 31, 2024	**196,756**	**1,184,065**
Issued on exercise of stock options	**2,366**	**5,764**
Transfer from contributed surplus on exercise of stock options	**-**	**2,788**
Released upon vesting of restricted share units	**683**	**3,257**
Balance at December 31, 2025	**199,805**	**1,195,874**

Stock options

In April 2025, the Company discontinued the ability to issue any additional stock options under its Incentive Stock Option Plan. The stock options granted prior to April 2025 will be settled through the issuance of new common shares of the Company which vest in equal tranches over a three year period and have a maximum term of five years to expiry.

The following table summarizes the change in stock options outstanding:

	Number of Options (000s)	Average Exercise Price ($/share)
Balance at December 31, 2023	9,697	3.74
Granted	2,315	6.09
Exercised [1]	(1,836)	2.76
Forfeited	(205)	6.19
Balance at December 31, 2024	**9,971**	**4.41**
Granted	**35**	**5.78**
Exercised [1]	**(2,366)**	**2.44**
Forfeited	**(110)**	**5.74**
Balance at December 31, 2025	**7,530**	**5.02**

(1) The average share price on the date stock options were exercised during the year ended December 31, 2025 was $7.22 per common share ($6.19 per common share on average during the year ended December 31, 2024).

The total fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions as follows:

	Year ended December 31	
	2025	2024
Risk-free interest rate	**2.54%**	3.83%
Expected life (years)	**3.0**	3.5
Expected volatility [1]	**38.4%**	52.2%
Expected dividend yield	**0.0%**	0.0%
Expected forfeiture rate	**5.0%**	5.1%
Fair value of options granted during the year ($/share)	**1.67**	2.51

(1) The expected volatility for options granted is estimated based on Kelt's historical volatility over the expected life.

The following table summarizes information regarding stock options outstanding at December 31, 2025:

Range of exercise prices per common share	Number of options outstanding (000s)	Weighted average remaining term (years)	Weighted average exercise price for options outstanding ($/share)	Number of options exercisable (000s)	Weighted average exercise price for options exercisable ($/share)
$2.01 to $4.00	1,278	0.2	2.75	1,278	2.75
$4.01 to $6.00	3,952	1.6	5.08	3,365	5.14
$6.01 to $8.00	2,300	3.2	6.19	823	6.26
Total	**7,530**	**1.9**	**5.02**	**5,466**	**4.75**

Restricted share units

The restricted share unit plan includes restricted share units ("RSUs") that may be granted to officers, directors and employees. The RSUs granted under the RSU Plan are to be settled through the issuance of new common shares upon vesting. RSUs vest in two equal tranches with the first half vesting after two years and the second half after three years.

The following table summarizes the change in RSUs outstanding:

	Number of RSUs (000s)
Balance at December 31, 2023	1,742
Granted	558
Released upon vesting	(414)
Forfeited	(58)
Balance at December 31, 2024	**1,828**
Granted	**610**
Released upon vesting	**(683)**
Forfeited	**(54)**
Balance at December 31, 2025	**1,701**

Performance share units

In April 2025, the Company's shareholders approved a PSU plan, under its long-term incentive compensation strategy, designed to align the interests of executives and employees with those of shareholders. The approval of the PSU plan was made in conjunction with the discontinuation of issuing any additional shares under the Company's Stock Option Plan.

The PSU plan provides for the issuance of equity-settled awards that vest based on the achievement of defined performance criteria over a rolling three-year period.

Each PSU entitles the holder to receive common shares upon vesting, with the number of shares issued ranging from 0% to 200% of the target award. The final number of shares delivered is determined by a Payout Multiplier, which is calculated based on the Company's performance against pre-established targets over the vesting period.

The following table summarizes the change in PSUs outstanding:

	Number of PSUs (000s)
Balance at December 31, 2024	**-**
Granted	**752**
Released upon vesting	**-**
Forfeited	**(11)**
Balance at December 31, 2025	**741**

The total fair value associated with stock options, RSUs, and PSUs is recognized over the service period using graded vesting, resulting in share based compensation expense as follows:

	Year ended December 31	
	2025	2024
Stock options	**3,114**	5,266
Restricted share units	**3,530**	3,580
Performance share units	**1,169**	-
Total share based compensation expense	**7,813**	8,846

Weighted average number of common shares

The table below summarizes the weighted average number of common shares outstanding used in the calculation of basic and diluted net income per common share:

	Year ended December 31	
(000s of common shares)	**2025**	2024
Weighted average common shares outstanding, basic	**198,838**	195,719
Effect of dilution from stock options, RSUs, and PSUs	**3,267**	3,912
Weighted average common shares outstanding, diluted	**202,105**	199,631

The treasury stock method is used to determine the dilutive effect of stock options, RSUs and PSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share.

10. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include cash and cash equivalents, accounts receivable and accrued sales, deposits, accounts payable and accrued liabilities, derivative financial instruments, lease liabilities and bank debt. The Company is exposed to financial risks arising from its financial assets and liabilities that include credit and liquidity risk in addition to the market risks associated with commodity prices, and interest and foreign exchange rates. Net income, cash flows and the fair value of financial assets and liabilities may fluctuate due to movement in market prices or as a result of the Company's exposure to credit and liquidity risks.

The objective of the Company's risk management is to manage and control market risk exposures within acceptable limits, while maximizing long-term returns. All such transactions are conducted in accordance with the Company's risk management policy that permits management to enter into commodity price agreements, provided that:

i) the contracts are not entered into for speculative purposes;
ii) the total notional quantity hedged, at the time of entering into the contract, does not exceed 65% of average daily production; and
iii) the contracted term does not exceed 36 months.

Commodity price risk

Inherent to the business of producing oil and gas, cash provided by operating activities is subject to commodity price risk. Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices are impacted by economic events that dictate the levels of supply and demand as well as the currency exchange rate relationship between the Canadian and U.S. dollar.

As of December 31, 2025, the following commodity price derivative financial instrument contracts are outstanding:

Crude oil derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
WTI fixed price (1)	500 bbl/d	CAD$92.85/bbl	Jan 26 – Mar 26
WTI fixed price	500 bbl/d	CAD$88.20/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$89.35/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.10/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.15/bbl	Jan 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$90.75/bbl	Jan 26 – Jun 26
WTI fixed price (2)	500 bbl/d	CAD$91.90/bbl	Jan 26 – Jun 26
WTI fixed price (3)	500 bbl/d	CAD$90.50/bbl	Jan 26 – Jun 26
WTI fixed price (4)	500 bbl/d	CAD$90.63/bbl	Jan 26 – Jun 26

(1) Includes a fixed price WTI ("West Texas Intermediate") oil swap option to sell 500 bbl/d for Apr-Jun 2026 at CAD$92.85/bbl exercisable on March 31, 2026.

(2) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$91.90/bbl exercisable on June 30, 2026.
(3) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.50/bbl exercisable on June 30, 2026.
(4) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jul-Dec 2026 at CAD$90.63/bbl exercisable on June 30, 2026.

NGL derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
OPIS-Conway propane fixed price	250 bbl/d	USD$33.60/bbl	Jan 26 – Mar 26
OPIS-Conway propane	250 bbl/d	Monthly OPIS-Conway calculated at 46% of the floating monthly WTI price	Jan 26 – Mar 26

Natural gas derivative financial instrument

Contract Type (1)	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX (1) call	20,000 MMBtu/d	USD$5.50/MMBtu	Jan 26 – Dec 26
AECO (2) 7A put	21,000 GJ/d	CAD$2.80/GJ	Jan 26 – Dec 26

(1) New York Mercantile Exchange (“NYMEX”)
(2) Alberta Energy Company “C” Meter Station of the NOVA Pipeline System (“AECO”)

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating AESO Power Pool Price divided by the fixed heat rate. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is calculated as the difference between the forecasted Floating AESO Power Pool Price divided by the fixed heat rate, less the forecasted AECO 5A price.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price (1)	Remaining Term
Physical delivery	7,349 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.75 GJ/MWh	Jan 26 – Dec 26

(1) Alberta Electric System Operator (“AESO”)

The Company has the following natural gas physical supply agreements for delivery to the Nova Inventory Transfer point, where the Company receives a price equal to the Floating Japan/Korea Marker LNG Price multiplied by 22% and the Floating Dutch TTF Gas Price multiplied by 22%. These supply agreements contain an embedded derivative where the fair value of the embedded derivative is based upon the future price in each respective market.

Natural gas embedded derivative

Contract Type	Notional Volume	Contract Price	Remaining Term
Physical delivery	5,000 MMBtu/d	Floating JKM (Japan/Korea Marker) Price (USD/MMBtu) multiplied by 22.0%	Jan 26 – Dec 26
Physical delivery	5,000 MMBtu/d	Floating TTF (Title Transfer Facility Netherlands) Price (USD/MMBtu) multiplied by 22.0%	Jan 26 – Dec 26

Subsequent to December 31, 2025, the Company entered into the following commodity price derivative financial instrument contracts:

Crude oil derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
WTI fixed price	300 bbl/d	CAD$130.00/bbl	Apr 26 – Jun 26
WTI fixed price	300 bbl/d	CAD$130.00/bbl	Apr 26 – Jun 26
WTI fixed price	500 bbl/d	CAD$99.30/bbl	Apr 26 – Dec 26
WTI fixed price (1)	500 bbl/d	CAD$85.00/bbl	Jul 26 – Dec 26
WTI fixed price	500 bbl/d	CAD$87.65/bbl	Jul 26 – Sept 26
WTI fixed price	500 bbl/d	CAD$85.65/bbl	Oct 26 – Dec 26

(1) Includes a fixed price WTI oil swap option to sell 500 bbl/d for Jan-Jun 2027 at CAD$85.00/bbl exercisable on December 31, 2026.

Electricity derivative financial instrument swap

Contract Type	Notional Volume	Contract Price	Remaining Term
AESO fixed price	24 MW/d	50.25 CAD per MWh	Feb 26 – Dec 26
AESO fixed price	24 MW/d	45.25 CAD per MWh	Mar 26 – Dec 26

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Credit Facility which is subject to a floating interest rate. Based on bank debt balance as of December 31, 2025 of $179.9 million, an increase (decrease) in the market rate of interest by 25 basis points would have increased (decreased) annualized interest expense by $0.5 million. As of December 31, 2025, there are no interest rate risk management contracts outstanding.

Foreign exchange risk

Kelt is exposed to fluctuations of the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing and from exposure from certain U.S. dollar denominated marketing arrangements.

As at December 31, 2025, the following foreign exchange derivative financial instrument contracts are outstanding:

Foreign exchange derivative financial instrument

Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward (1)	USD$2.0 million/month	$1.4025 CAD/USD	Jan 26 – Dec 26

(1) Contract includes an option that extends the contract into the 2027 calendar year at a strike price of $1.4025 CAD/USD if the spot CAD/USD is $1.4025 CAD/USD or higher on December 31, 2026. The contract also includes a knock out provision that if the spot CAD/USD trades at or below $1.3250 CAD/USD anytime between the trade date of November 3, 2025 to December 31, 2026, the option to extend into 2027 is cancelled.

Subsequent to December 31, 2025, the Company entered into the following foreign exchange derivative financial instrument contracts:

Foreign exchange derivative financial instrument

Contract Type	Notional Volume	Strike Rate	Remaining Term
Average rate forward	USD$1.0 million/month	$1.3800 CAD/USD	Feb 26 – Dec 26

Gains and losses on derivative financial instrument contracts

The table below summarizes realized and unrealized gains (losses) on derivative financial instrument contracts:

	Year ended December 31	
	2025	2024
Realized gain		
Derivative financial instrument contracts	**26,967**	4,253
Natural gas embedded derivative	**775**	-
Total realized gain	**27,742**	4,253
Unrealized gain (loss)		
Derivative financial instrument contracts	**15,057**	(5,920)
Natural gas embedded derivative	**2,185**	734
Total unrealized gain (loss)	**17,242**	(5,186)
Gain (loss) on derivative financial instruments	**44,984**	(933)

Fair value measurements

The Company classifies fair value measurements using a hierarchy that reflects the significance of the inputs used in making the measurements. The Company maximizes the use of observable inputs when preparing calculations of fair value, where possible. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy. The fair value hierarchy has the following levels:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

The fair value of cash and cash equivalents, accounts receivable and accrued sales, deposits, accounts payable and accrued liabilities approximate their carrying value due to the short term to maturity of these instruments. Bank debt bears interest at a floating market rate and accordingly the fair market value of bank debt approximates the carrying amount. Derivative financial instruments are classified as Level 2.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchies:

	Carrying Value ("CV")			Fair Value		
Balance as at December 31, 2025	Gross	Netting [(1)]	Net CV	Level 1	Level 2	Level 3
Financial assets						
Natural gas embedded derivative	2,919	-	2,919	-	2,919	-
Derivative financial instrument	14,129	-	14,129	-	14,129	-
Financial liabilities						
Derivative financial instrument	1,033	-	1,033	-	1,033	-
	Carrying Value ("CV")			Fair Value		
Balance as at December 31, 2024	Gross	Netting [(1)]	Net CV	Level 1	Level 2	Level 3
Financial assets						
Natural gas embedded derivative	734	-	734	-	734	-
Derivative financial instrument	5,975	-	5,975	-	5,975	-
Financial liabilities						
Derivative financial instrument	7,936	-	7,936	-	7,936	-

(1) Financial assets and liabilities are only offset if there is a legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Kelt offsets derivative contracts assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same.

Credit risk

As at December 31, 2025, the carrying amount of cash and cash equivalents, accounts receivable and accrued sales, deposits, and derivative financial instruments represent the Company's maximum credit exposure. Potential losses are mitigated from this credit exposure by holding cash and cash equivalents with a Canadian chartered bank, and restricting derivative financial instrument transactions to counterparties that are all investment grade. The remaining credit risk exposure arises primarily from receivables from oil and gas marketers and joint venture partners.

The composition of accounts receivable is set out in the following table:

	December 31, 2025	December 31, 2024
Joint venture partners	**6,076**	5,893
Oil and gas marketers	**53,572**	45,708
GST input tax credits	**2,664**	4,036
Derivative financial instrument contracts	**1,951**	1,314
Other	**270**	3,638
Expected credit loss provision	**(338)**	(353)
Accounts receivable and accrued sales	**64,195**	60,236

During the year ended December 31, 2025, sales to three oil and gas marketers accounted for approximately 15%, 16%, and 22% of total sales. During the year ended December 31, 2024, sales to two oil and gas marketers accounted for approximately 29% and 31%, of total sales. Credit risk from oil and gas marketers is mitigated through transacting with investment grade rating counterparties in the majority of its oil and gas marketing transactions.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas; this occurs on the 25th day following the month of sale. As a result, oil and gas marketers revenues are current. All other accounts receivable are generally contractually due within 30-90 days.

As of December 31, 2025, the collection risk on outstanding accounts receivable balances is considered low as less than 1.0% of the accounts receivable balance are outstanding for more than 90 days (December 31, 2024 - 1.0%). The balance of accounts receivable outstanding for more than 90 days relates primarily to receivables from joint venture partners. Credit risk related to joint venture receivables is mitigated by obtaining partner approval of significant capital expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint venture partners. The Company has the ability to withhold production from joint venture partners in the event of non-payment or may be able to register security on the assets of joint venture partners.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. Financial obligations include accounts payable, derivative financial instruments, lease liabilities and bank debt. Liquidity risk is managed through the budgeting process, which sets out expected debt levels, capital expenditures and funds from operations. In addition, derivative financial instrument contracts may be used to protect future sales. The Board of Directors approves an annual capital expenditure budget, which is regularly monitored and updated as necessary in response to changing capital requirements and expected sales.

The capital intensive nature of Kelt's operations may create a working capital deficiency position during periods with high levels of capital investment. However, the Company targets to maintain sufficient unused bank credit lines or other liquidity to satisfy such working capital deficiencies.

The table below outlines a contractual maturity analysis for Kelt's financial liabilities as at December 31, 2025:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	78,046	-	-	**78,046**
Derivative financial instruments	1,033	-	-	**1,033**
Lease liability	633	385	-	**1,018**
Bank debt and estimated interest [(1)]	10,792	179,861	-	**190,653**
Total	**90,504**	**180,246**	**-**	**270,750**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 6.0% for the year ended December 31, 2025, applied to the principal balance outstanding as at that date.

Capital Management

The Company's capital structure is comprised of shareholders' capital, bank debt and working capital. The Company's objective when managing its capital structure is to maintain financial flexibility in order to meet financial obligations, as well as finance future capital expenditures relating to exploration, development and acquisition activities.

The Company may increase or decrease capital expenditures including acquisitions and dispositions, issue new shares, issue new debt or repay existing debt, if any, according to market conditions in order to maintain its financial flexibility.

Adjusted funds from operations, net debt and net debt to adjusted funds from operations ratio

Management considers adjusted funds from operations, net debt and net debt to adjusted funds from operations ratio as key capital management measures that demonstrate the Company's ability to meet its financial obligations and cash flow available to fund its capital program, and to assess the Company's liquidity at a point in time while monitoring its capital structure and short-term financing requirements. The Company targets a net debt to adjusted funds from operations ratio of less than 2.0 times.

Adjusted funds from operations, net debt and net debt to adjusted funds are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Adjusted funds from operations are calculated as follows:

	Year ended December 31	
	2025	2024
Cash provided by operating activities	**264,256**	209,145
Change in non-cash working capital	**(6,079)**	7,797
Settlement of decommissioning obligations	**3,348**	5,036
Adjusted funds from operations	**261,525**	221,978

Net debt and net debt to adjusted funds from operations ratios are calculated as follows:

	December 31, 2025	December 31, 2024
Bank debt	**179,861**	108,993
Accounts payable and accrued liabilities	**78,046**	80,463
Cash and cash equivalents	**(90)**	(228)
Accounts receivable and accrued sales	**(64,195)**	(60,236)
Prepaid expenses and deposits	**(3,919)**	(4,109)
Net debt	**189,703**	124,883
Adjusted funds from operations	**261,525**	221,978
Net debt to adjusted funds from operations ratio	**0.7**	0.6

As described in note 6, there are no financial covenants under the Credit Facility agreement and Kelt is in compliance with all other covenants.

11. INCOME TAXES

Kelt was not required to pay income taxes in the current or prior year. Tax pools and losses available to reduce taxable income as of December 31, 2025 are estimated to be approximately $966.7 million (December 31, 2024 – $896.7 million).

The following table reconciles income taxes calculated at the weighted average Canadian statutory rate with the actual provision for deferred income taxes per the Consolidated Statement of Net Income and Comprehensive Net Income:

	Year ended December 31	
	2025	2024
Net income before income taxes	**83,991**	63,156
Canadian statutory tax rate	**22.6%**	23.0%
Expected income tax expense	**18,973**	14,535
Increase resulting from:		
Non-deductible expenses (1)	**1,815**	2,048
True-up of tax pools	**145**	-
Valuation allowance (2)	**-**	1,150
Deferred income tax expense	**20,933**	17,733

(1) Non-deductible expenses primarily include share based compensation.

(2) The 2024 valuation allowance is a result of a financial statement write-off of an investment in securities of a third-party company.

The Canadian statutory tax rate per the rate reconciliation above represents the weighted average combined federal and provincial corporate tax rate. The federal corporate tax rate is 15.0% and the annual provincial tax rate in Alberta is 8.0% and is 12% in British Columbia.

The movement in deferred income tax assets and liabilities, without taking into consideration the offsetting balances within the same tax jurisdiction are as follows:

Deferred income tax asset (liability)	Balance at December 31, 2024	Recognized in profit and CI(1)	Recognized in balance sheet	**Balance at December 31, 2025**
Derivative financial instruments	282	(3,966)	-	**(3,684)**
PP&E and E&E	(177,701)	(16,014)	-	**(193,715)**
Decommissioning obligations	23,452	(1,917)	-	**21,535**
Lease liability	472	(288)	-	**184**
Non-capital losses (2)	66,261	1,252	-	**67,513**
Net deferred tax liability	(87,234)	(20,933)	-	**(108,167)**

Deferred income tax asset (liability)	Balance at December 31, 2023	Recognized in profit and CI(1)	Recognized in balance sheet	Balance at December 31, 2024
Derivative financial instruments	(911)	1,193	-	282
PP&E and E&E	(152,736)	(24,965)	-	(177,701)
Decommissioning obligations	23,204	248	-	23,452
Lease liability	286	186	-	472
Non-capital losses (2)	60,656	5,605	-	66,261
Net deferred tax liability	(69,501)	(17,733)	-	(87,234)

(1) Comprehensive income has been abbreviated as “CI”.

(2) The Company’s non-capital losses expire in years 2035 to 2045.

The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including future capital expenditures and future operating results.

12. PETROLEUM AND NATURAL GAS SALES

Kelt sells its oil, natural gas, and NGLs production under variable price contracts. The transaction price is based on a benchmark commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula (apart from the benchmark commodity price) can be either fixed or variable, depending on the contract terms. Sales are typically collected on the 25th day of the month following the prior month's production, with sales being recorded once the product is delivered to a contractually agreed upon delivery point.

Kelt generates oil treating, gas processing, and other services income from fees charged to third parties provided at facilities where Kelt has an ownership interest. Marketing revenue is generated from the sales of third-party volumes related to its oil blending and natural gas operations, with the production being sold under the same terms as the variable price contracts discussed above.

Kelt sells some of its natural gas outside of Alberta and British Columbia where title transfer occurs prior to the market location where the benchmark commodity price is determined. For the year ended December 31, 2025, the transportation costs that occurred after title transfer takes place, and which is included in gas production sales, was $15.6 million (December 31, 2024 – $15.0 million).

The following table presents Kelt's production disaggregated by sales source:

	December 31, 2025	December 31, 2024
Oil production	**281,913**	296,999
Oil treating and other	**876**	921
NGLs production	**72,749**	63,970
Gas production	**137,899**	87,425
Gas processing and other	**1,953**	2,544
Marketing revenue	**17,695**	16,573
Total petroleum and natural gas sales	**513,085**	468,432

Included in accounts receivable at December 31, 2025 is $53.6 million (December 31, 2024 - $45.7 million) of accrued oil and gas sales related to Kelt's December 2025 oil and gas production.

13. FINANCING EXPENSES

	Year ended December 31	
	2025	2024
Total interest expense	**11,330**	3,674
Accretion of decommissioning obligations [note 7]	**3,264**	3,082
Total financing expense	**14,594**	6,756

14. COMMITMENTS

As of December 31, 2025, the Company is committed to future payments under the following agreements:

	2026	2027	2028	2029	2030	Thereafter
Firm processing commitments	67,400	72,067	78,513	79,285	80,519	400,807
Firm transportation commitments	47,777	48,215	51,911	41,143	33,768	110,874
Total annual commitments	**115,177**	**120,282**	**130,424**	**120,428**	**114,287**	**511,681**

15. GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

The following table summarizes significant components of G&A expenses:

	Year ended December 31	
	2025	2024
Salaries and benefits [1]	**15,635**	14,855
Other G&A expenses	**6,175**	6,250
G&A expenses before recoveries	**21,810**	21,105
Overhead recoveries	**(8,317)**	(8,833)
G&A expense	**13,493**	12,272

(1) Refer to additional information regarding salaries and benefits paid to key management personnel in note 17 of these financial statements.

16. SUPPLEMENTAL CASH FLOW INFORMATION

	Year ended December 31	
Changes in non-cash working capital	**2025**	2024
Accounts receivable and accrued sales	**(3,959)**	(7,590)
Prepaid expenses and deposits	**190**	1,079
Accounts payable and accrued liabilities	**(2,417)**	(4,708)
Change in non-cash working capital	**(6,186)**	(11,219)
Relating to:		
Operating activities	**6,079**	(7,797)
Investing activities	**(12,265)**	(3,422)
Change in non-cash working capital	**(6,186)**	(11,219)

During the reporting period, the following cash outlays were made in respect of interest and taxes:

	Year ended December 31	
Cash outlays in respect of interest and taxes	**2025**	2024
Interest and standby fees on bank debt	**9,818**	3,070
Taxes [1]	**-**	-

(1) Kelt was not required to pay cash income taxes as there were sufficient income tax deductions available to shelter taxable income (note 11).

17. RELATED PARTY TRANSACTIONS

The Company has engaged the services of a registrar and transfer agent where an officer of Kelt is a director of the company. During the year ended December 31, 2025, the Company incurred $0.2 million (December 31, 2024 – $0.1 million) in disbursements to this related party. As of December 31, 2025, the Company no longer considers a law firm, where a Kelt Board Member was previously a partner at, to be a related party.

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Company. The following table summarizes compensation paid or payable to officers and directors of the Company:

	Year ended December 31	
	2025	2024
Salaries, bonuses and other benefits	**3,589**	3,509
Share based compensation	**3,665**	3,870
Total compensation	**7,254**	7,379

During the year ended December 31, 2025, key management personnel were granted 211,138 RSUs, and 351,918

PSUs. During the year ended December 31, 2024, key management personnel were granted 935,000 stock options with an exercise price of $6.06 per share and 173,000 RSUs.

ABBREVIATIONS

A&D	Acquisitions and dispositions
AECO	Alberta Energy Company “C” Meter Station of the NOVA Pipeline System
AESO	Alberta Electric System Operator
AT	After income taxes
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
BT	Before income taxes
CA$/CAD	Canadian Dollar
CGU	Cash Generating Unit
CORRA	Canadian Overnight Repo Rate Average
Dawn	Gas traded at Union Gas' Dawn Hub in Dawn Township, Ontario
E&E	Exploration and Evaluation
FDC	Future Development Capital
G&A	General and Administration
GJ	gigajoules
LNG	Liquefied Natural Gas
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
MD&A	Management’s Discussion and Analysis
MMBtu	million British Thermal Units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MSW	Mountain sweet blend crude oil
NGLs	Natural Gas Liquids
NGX	Natural Gas Exchange Inc. (Canada)
NGTL	Nova Gas Transmission Line
NIT	NOVA Inventory Transfer (“AB-NIT”), being the reference price at the AECO Hub
NYMEX	New York Mercantile Exchange
Oil	Oil includes crude oil and field condensate
OPEC+	The Organization of Petroleum Exporting Countries along with 10 additional oil-producing countries
P&NG	Petroleum and Natural Gas
Q1	First quarter ended March 31st
Q2	Second quarter ended June 30th
Q3	Third quarter ended September 30th
Q4	Fourth quarter ended December 31st
SBC	Share Based Compensation
SEDAR+	System for Electronic Document Analysis and Retrieval
Station 2	Spectra Energy receipt location
TSX	Toronto Stock Exchange
US$/USD	United States dollar
WTI	West Texas Intermediate
YTD	Year to date
1P	Proved reserves
2P	Proved plus probable reserves

CONVERSION OF UNITS

Imperial = Metric

1 acre = 0.4 hectares

2.5 acres = 1 hectare

1 bbl = 0.159 cubic metres

6.29 bbls = 1 cubic metre

1 foot = 0.3048 metres

3.281 feet = 1 metre

1 Mcf = 28.2 cubic metres

0.035 Mcf = 1 cubic metre

1 mile = 1.61 kilometres

0.62 miles = 1 kilometre

1 MMBtu = 1.054 GJ

0.949 MMBtu = 1 GJ

Natural gas is equated to oil on the basis of 6 Mcf = 1 BOE

Sulphur is equated to gas on the basis of 1LT = 10 Mcf (1 BOE = 0.6 LT)

CORPORATE INFORMATION

BOARD OF DIRECTORS

William C. Guinan [5, 8, 9]
Board Chair, Independent

Jennifer Haskey [2, 6, 10]
Director, Independent

Ray Kwan [1, 7]
Director, Independent

Neil G. Sinclair [4, 8, 10]
Director, Independent

Janet E. Vellutini [3, 6, 7]
Director, Independent

David J. Wilson [9]
President & Chief Executive Officer,
Kelt Exploration Ltd.

1 chair, audit committee
2 chair, reserves committee
3 chair, compensation and corporate governance committee
4 chair, health, safety, environment and sustainability committee
5 chair, nominating committee
6 member, audit committee
7 member, reserves committee
8 member, compensation and corporate governance committee
9 member, health, safety and environment and sustainability committee
10 member, nominating committee

HEAD OFFICE

Suite 300, East Tower, 311 Sixth Avenue S.W.
Calgary, Alberta T2P 3H2

Phone: 403.294.0154
Fax: 403.291.0155
www.keltexploration.com

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company
350-300 5th Avenue S.W.
Calgary, Alberta T2P 3C4

LEGAL COUNSEL

Borden Ladner Gervais LLP
Centennial Place, East Tower,
Suite 1900, 520 Fourth Avenue S.W.
Calgary, Alberta T2P 0R3

OFFICERS

David J. Wilson
President & Chief Executive Officer

Sadiq H. Lalani
Vice President & Chief Financial Officer

Douglas J. Errico
Senior Vice President, Land and Corporate Development

Alan G. Franks
Vice President, Production

Bruce D. Gigg
Vice President, Engineering

David A. Gillis
Vice President, Finance

Douglas O. MacArthur
Vice President, Operations

Patrick W.G. Miles
Vice President, Exploration

Louise K. Lee
Corporate Secretary

AUDITORS

PricewaterhouseCoopers LLP
Suite 2900, 111 Fifth Avenue S.W.
Calgary, Alberta T2P 5L3

EVALUATION ENGINEERS

McDaniel & Associates Consultants Ltd
2000, 525 8th Ave SW
Calgary, Alberta T2P 1G1

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Common shares “KEL”

SUITE 300, EAST TOWER
311 SIXTH AVENUE SOUTH WEST
CALGARY, ALBERTA T2P 3H2