kelt exploration

ANNUAL REPORT

AS AT AND FOR THE YEAR ENDED

DECEMBER 31, 2022

FINANCIAL AND OPERATIONAL HIGHLIGHTS *(CA$ thousands, except as otherwise indicated)*	Three months ended December 31 **2022**	 2021	 %	Year ended December 31 **2022**	 2021	 %
FINANCIAL						
Petroleum and natural gas sales	**152,720**	120,523	27	**613,358**	316,763	94
Cash provided by operating activities	**63,742**	52,056	22	**306,022**	159,714	92
Adjusted funds from operations (1)	**92,851**	68,155	36	**326,992**	161,394	103
Basic ($/ common share) (1)	**0.48**	0.36	33	**1.71**	0.85	101
Diluted ($/ common share) (1)	**0.47**	0.35	34	**1.67**	0.85	96
Net income and comprehensive income	**54,238**	52,996	2	**158,758**	114,256	39
Basic ($/ common share)	**0.28**	0.28	-	**0.83**	0.61	36
Diluted ($/ common share)	**0.28**	0.28	-	**0.81**	0.60	35
Capital expenditures, net of A&D (1)	**68,594**	67,118	2	**317,540**	213,511	49
Total assets	**1,128,104**	913,497	23	**1,128,104**	913,497	23
Bank debt	**11,300**	1,150	883	**11,300**	1,150	883
Net debt (1)	**9,789**	28,220	-65	**9,789**	28,220	-65
Shareholders' equity	**901,424**	722,724	25	**901,424**	722,724	25
Weighted average shares outstanding (000s)						
Basic	**191,812**	189,134	1	**191,101**	188,800	1
Diluted	**195,828**	192,676	2	**195,456**	190,807	2
OPERATIONS						
Average daily production						
Oil (bbls/d) (2)	**6,416**	6,624	-3	**5,640**	4,692	20
NGLs (bbls/d)	**3,478**	3,255	7	**4,049**	3,154	28
Gas (mcf/d)	**108,849**	95,616	14	**105,280**	78,846	34
Combined (BOE/d)	**28,036**	25,815	9	**27,236**	20,987	30
Production per million common shares (BOE/d) (1)	**146**	136	7	**143**	111	29
Net realized prices, before financial instruments (1)						
Oil ($/bbl) (2)	**107.88**	91.43	18	**117.18**	81.30	44
NGLs ($/bbl)	**60.54**	50.03	21	**67.64**	40.03	69
Gas ($/mcf)	**6.52**	5.46	19	**6.63**	4.35	52
Operating netbacks ($/BOE) (1)						
Petroleum and natural gas sales	**59.21**	50.75	17	**61.70**	41.35	49
Cost of purchases	**(3.30)**	(0.74)	346	**(2.16)**	(0.83)	160
Combined net realized price, before financial instruments(1)	**55.91**	50.01	12	**59.54**	40.52	47
Realized gain (loss) on financial instruments	**1.66**	(2.62)	163	**(5.68)**	(2.14)	165
Combined net realized price, after financial instruments (1)	**57.57**	47.39	21	**53.86**	38.38	40
Royalties	**(6.15)**	(4.17)	47	**(6.60)**	(3.58)	84
Production expense	**(10.90)**	(9.91)	10	**(10.22)**	(9.13)	12
Transportation expense	**(3.03)**	(3.31)	-8	**(3.06)**	(3.38)	-9
Operating netback (1)	**37.49**	30.00	25	**33.98**	22.29	52
Land holdings						
Gross acres	**795,559**	722,281	3	**795,559**	722,281	3
Net acres	**579,857**	558,763	4	**579,857**	558,763	4
Reserves – proved plus probable						
Crude oil and liquids (mbbls) (2)	**129,479**	104,824	24	**129,479**	104,824	24
Gas (mmcf)	**1,267,931**	895,948	42	**1,267,931**	895,948	42
Combined (mBOE)	**340,801**	254,149	34	**340,801**	254,149	34

(1) Refer to advisories regarding non-GAAP and other financial measures.
(2) “Liquids” include field condensate and NGLs; “Oil” includes crude oil and field condensate combined.

MESSAGE TO SHAREHOLDERS

Kelt Exploration Ltd. ("Kelt" or the "Company") reports its financial and operating results to shareholders for the fourth quarter and year ended December 31, 2022.

Average production for the three months ended December 31, 2022 was 28,036 BOE per day, up 9% compared to average production of 25,815 BOE per day during the fourth quarter of 2021. Average production for 2022 was 27,236 BOE per day, an increase of 30% from average production of 20,987 BOE per day in 2021. Production for the three months ended December 31, 2022 was weighted 35% to oil and NGLs and 65% to gas.

Kelt's petroleum and natural gas sales during the fourth quarter of 2022 increased 27% to $152.7 million, up from $120.5 million in the same period of the previous year. Petroleum and natural gas sales for the year were $613.4 million, up 94% from $316.8 million in 2021. Kelt's net realized average oil price during the fourth quarter of 2022 was $107.88 per barrel, up 18% from $91.43 per barrel in the fourth quarter of 2021. The Company's net realized average NGLs price during the fourth quarter of 2022 was $60.54 per barrel, up 21% from $50.03 per barrel in the fourth quarter of 2021. Kelt's net realized average gas price for the fourth quarter of 2022 was $6.52 per Mcf, up 19% from $5.46 per Mcf in the fourth quarter of 2021.

For the three months ended December 31, 2022, adjusted funds from operations was $92.9 million ($0.47 per share, diluted), compared to $68.2 million ($0.35 per share, diluted) in the fourth quarter of 2021. Year over year, adjusted funds from operations increased 103% to $327.0 million ($1.67 per share, diluted) from $161.4 million ($0.85 per share, diluted) in 2021. During 2022, Kelt recorded net income of $158.8 million ($0.81 per share, diluted) compared to $114.3 million ($0.60 per share, diluted) in the previous year.

At December 31, 2022, Kelt had net debt of $9.8 million compared to $28.2 million at December 31, 2021. At a net debt to adjusted funds from operations ratio of 0.03 times, Kelt continues to maintain its strong financial position.

Net capital expenditures incurred during the three months ended December 31, 2022 were $68.6 million, up 2% compared to net capital expenditures of $67.1 million during the fourth quarter of 2021. During the fourth quarter of 2022, the Company spent $31.6 million on drill and complete operations and $35.9 million on well equipment, facilities and pipelines.

As at December 31, 2022, Kelt's net working interest land holdings were 579,857 acres (906 sections). Kelt is focused on long-term value creation by accumulating significant land acreage on resource style plays, with a primary focus on the Triassic Montney and Charlie Lake plays. At December 31, 2022, Kelt's net Montney land holdings were 344,274 acres (538 sections) and its Charlie Lake holdings were 88,447 net acres (138 sections).

At Oak, after more than a year of production history from wells that were put on production in late 2021 and early 2022, Sproule Associates Limited ("Sproule") has increased their EUR estimates with an improved type-curve forecast on a Montney horizontal well. At December 31, 2022, Sproule's estimated EUR per well is 1.3 million BOE, up 34% from their previous estimate at December 31, 2021 of 968,000 BOE. Kelt recently put on production two additional Montney wells at Oak that were the first to be drilled in a wine rack methodology. Wine racking wells in the upper Montney will allow for increased inventory. After just over 90 days, both wells are currently exceeding the latest Sproule type-curve estimate. Kelt expects to drill five wells and complete six wells at Oak during 2023.

Kelt has arranged for gas produced from its Oak property to be sold at various pricing point hubs including Station 2, Chicago ACE, Marcellus TZ4-L300 and Sumas. With recent weakness in Station 2 prices and with anticipated further volatility during the summer relating to industry pipeline and facility maintenance, the Company has temporarily deferred the drilling of seven wells at Oak that were previously planned for 2023. The Company's capital expenditure program remains flexible, and the drilling and completion of these wells could be re-instated with positive movement in Station 2 gas prices.

At Pouce Coupe, Kelt plans to drill and complete four Montney wells in the oil-prone area of the Company's land base during 2023. At Pouce Coupe West, Kelt has deferred the drilling of its high deliverability Montney gas wells during the current environment of weaker western Canadian gas markets. At Spirit River, Progress, Pouce Coupe North and Wembley, Kelt expects to follow up with the very successful 2022 Charlie Lake drilling program with up to nine additional Charlie Lake horizontal wells in 2023. Production additions from the drilling program in the Company's Pouce Coupe/ Progress/Spirit River Division is expected to offset total corporate declines during 2023.

At Wembley/Pipestone, Kelt plans to drill nine wells and complete ten wells during 2023. This program is anticipated to fulfill the Company's additional gas processing capacity that is expected to be made available to Kelt in the Wembley/Pipestone area at a third-party facility in late 2023 or early 2024. Despite incurring all of the capital required to complete this program, the Company has not included any production from these wells into its forecasted 2023 production guidance. Upon start-up, these wells are expected to add approximately 6,000 to 7,000 BOE per day of new production weighted approximately 60% oil and NGLs and 40% gas.

With the recent weakness in natural gas prices, Kelt has revised its 2023 outlook and guidance. After a warm January 2023 in the US Northeast and Midwest that reduced natural gas demand significantly and excess supply in response to potential LNG exports off the US Gulf Coast being disrupted since June 2022 due to a major facility outage, North American natural gas prices have declined precipitously. The Company has changed its 2023 forecasted average natural gas price assumptions as follows: the NYMEX Henry Hub natural gas price is forecasted to average US$3.39 per MMBtu, down 32% from the previous forecast of US$5.00 per MMBtu; the AECO daily index natural gas price is forecasted to average $2.94 per GJ, down 32% from the previous forecast of $4.30 per GJ; and Kelt's realized natural gas price is forecasted to average $3.64 per Mcf, down 31% from the previous forecast of $5.25 per Mcf;. The Company will continue to monitor commodity prices and expects to provide updated 2023 guidance, if necessary, by mid-year.

Kelt has reduced its 2023 capital expenditure program to $285.0 million, down from $310.0 million in its previous guidance. Production in 2023 is forecasted to average between 32,000 and 34,000 BOE per day. Built into this forecast is certain third-party facility downtime expected during 2023 that Kelt has been made aware of. Average oil and NGLs production guidance of between 11,700 to 12,900 bbls per day remains unchanged from the Company's previous guidance. Despite reducing the number of wells to be drilled at Oak in 2023, the loss of potential oil and NGL production from these wells have been offset by much better performance of its oily Charlie Lake wells than previously forecasted. Average natural gas production is expected to average between 121.8 and 126.6 MMcf per day in 2023, a reduction of 6.0 MMcf per day (or 1,000 BOE per day) compared to the Company's previous guidance.

The reduction in forecasted natural gas prices has had the biggest impact to forecasted adjusted funds from operations. Adjusted funds from operations ("AFFO") is now forecasted to be $285.0 million in 2023, down by 16% or $53.0 million from Kelt's previous forecast. Kelt's capital expenditures for 2023 will match AFFO at $285.0 million. The Company's financial position continues to remain strong as Kelt is forecasting net debt of $14.8 million at the end of 2023 (or less than 0.1 times estimated 2023 AFFO), giving the Company the ability to act on additional opportunities as they arise.

Kelt expects to report to shareholders its 2023 first quarter results on or about May 4, 2023.

On behalf of the Board of Directors,

[signed]

David J. Wilson
President and Chief Executive Officer
March 3, 2023

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.sedar.com.

This Management's Discussion and Analysis ("MD&A") is dated March 3, 2023 and should be read in conjunction with the Company's audited consolidated annual financial statements and related notes as at and for the year ended December 31, 2022. The accompanying financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). The Company's Board of Directors approved and authorized the consolidated annual financial statements for issue on March 3, 2023.

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 "adjusted funds from operations", "annualized quarterly adjusted funds from operations", "adjusted funds from operations per common share", "petroleum and natural gas sales before marketing revenue" "petroleum and natural gas sales after cost of purchases", "operating netback", "net debt", "net realized prices" and "net debt to annualized quarterly 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. References to "oil" in this MD&A include crude oil and field condensate. References to "natural gas liquids" or "NGLs" include pentane, butane, propane, and ethane.

References to “liquids” include field condensate and NGLs. References to “gas” include natural gas and sulphur.

FINANCIAL AND OPERATING SUMMARY

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
FINANCIAL PERFORMANCE						
Petroleum and natural gas sales	**152,720**	120,523	27	**613,358**	316,763	94
Cash provided by operating activities	**63,742**	52,056	22	**306,022**	159,714	92
Adjusted funds from operations (1)	**92,851**	68,155	36	**326,992**	161,394	103
Diluted ($/ common share) (1)	**0.47**	0.35	34	**1.67**	0.85	96
Net income and comprehensive income	**54,238**	52,996	2	**158,758**	114,256	39
Diluted ($/ common share)	**0.28**	0.28	-	**0.81**	0.60	35
Capital expenditures, net of A&D (1)	**68,594**	67,118	2	**317,540**	213,511	49
Bank debt	**11,300**	1,150	883	**11,300**	1,150	883
Net debt (1)	**9,789**	28,220	-65	**9,789**	28,220	-65
OPERATIONAL PERFORMANCE						
Average daily production (BOE/d)	**28,036**	25,815	9	**27,236**	20,987	30
Combined net realized price, before financial instruments (1)	**55.91**	50.01	12	**59.54**	40.52	47
Combined net realized price, after financial instruments (1)	**57.57**	47.39	21	**53.86**	38.38	40
Operating netback (1)	**37.49**	30.00	25	**33.98**	22.29	52
Reserves – proved plus probable (mboe)	**340,801**	254,149	34	**340,801**	254,149	34

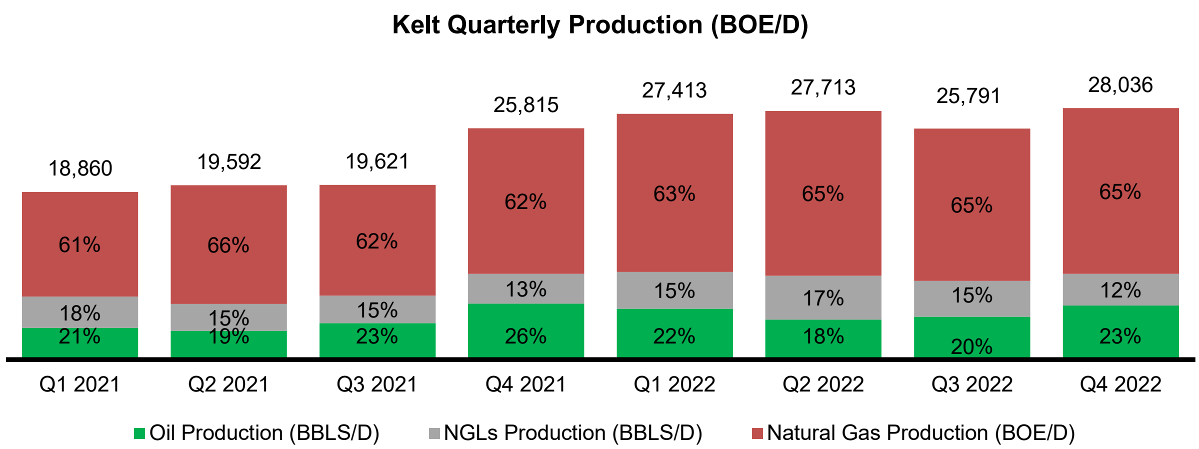
(1) Refer to advisories regarding non-GAAP and other financial measures.

Kelt’s key financial and operating results in the fourth quarter of 2022 are highlighted by the following:

- **Production** – Fourth quarter 2022 production averaged 28,036 BOE per day (35% oil/NGLs), an increase of 9% from both the fourth quarter of 2021 and the third quarter of 2022.
- **Petroleum and natural gas sales –** For the three months ended December 31, 2022, petroleum and natural gas sales was $152.7 million, an increase of 27% from $120.5 million in the fourth quarter of 2021. Kelt’s combined net realized price before financial instruments of $55.91 per BOE increased 12% from the fourth quarter of 2021.
- **Operating netback** – Kelt’s operating netback of $37.49 per BOE for the quarter ended December 31, 2022 increased by 25% from the fourth quarter of 2021. The increase in the operating netback per BOE was driven by higher crude oil and natural gas prices in 2022.
- **Cash provided by operating activities and adjusted funds from operations –** Cash provided by operating activities increased to $63.7 million in the fourth quarter of 2022 compared to $52.1 million in the fourth quarter of 2021. Adjusted funds from operations of $92.9 million during the three months ended December 31, 2022 ($0.47 per share, diluted) increased 36% from the fourth quarter of 2021.
- **Net income –** Kelt reported a net income of $54.2 million ($0.28 per common share, diluted) for the three months ended December 31, 2022, compared to a net income of $53.0 million ($0.28 per common share, diluted) in the comparative period in 2021.
- **Capital investments –** During the fourth quarter of 2022, capital expenditures, net of A&D, was $68.6 million and included the drilling of 3.0 net wells and completion of 6.0 net wells. Facilities, pipeline and well equipment spend was $35.9 million.
- **Liquidity –** The Company ended the quarter with net debt of $9.8 million.

- **Reserves -** The Company reported oil and gas reserves as at December 31, 2022:
    - Proved developed producing reserves of 61.1 million BOE (32% oil and NGLs), an increase of 39% from December 31, 2021;
    - Total proved reserves of 192.1 million BOE (40% oil and NGLs), an increase of 43% from December 31, 2021; and
    - Total proved plus probable reserves of 340.8 million BOE (38% oil and NGLs), an increase of 34% from December 31, 2021.

PRODUCTION



	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Average daily production:						
Oil (bbls/d) [(1)]	**6,416**	6,624	-3	**5,640**	4,692	20
NGLs (bbls/d)	**3,478**	3,255	7	**4,049**	3,154	28
Gas (mcf/d)	**108,849**	95,616	14	**105,280**	78,846	34
Combined (BOE/d)	**28,036**	25,815	9	**27,236**	20,987	30
Oil and NGLs weighting	**35%**	38%	-8	**36%**	37%	-3

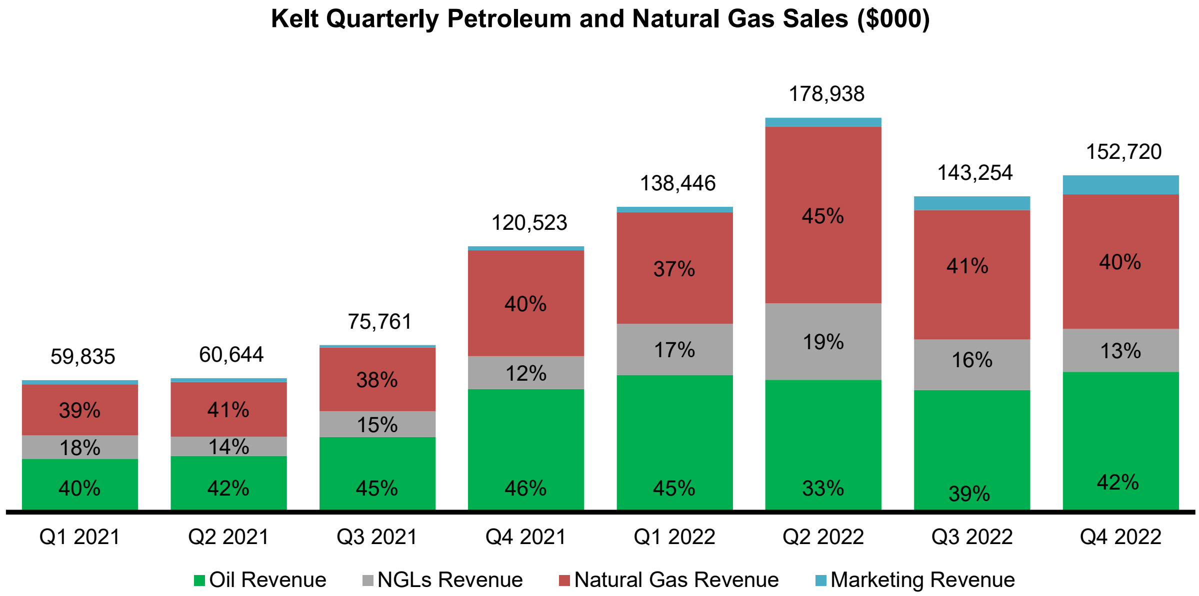
(1) "Oil" includes crude oil and field condensate combined

Average production for the three months ended December 31, 2022, increased 9% from the three months ended December 31, 2021. Average production for the twelve months ended December 31, 2022 increased 30% from the twelve months ended December 31, 2021. Kelt brought on production 30 gross wells (27.1 net wells) in 2022. The increase in production from the new wells was partially offset by natural declines, and limitations in the Company's natural gas processing takeaway capacity.

Average production for the three months ended December 31, 2022, increased 9% from the third quarter of 2022. Production increased in the fourth quarter of 2022 due to additional wells being brought on-production, and due to production in the third quarter of 2022 being constrained due to third party facility turnarounds and production temporarily shut in due to low AECO and Station 2 natural gas prices.

Oil and NGLs weighting of total production decreased in 2022 to 35% during the fourth quarter and to 36% for the year, versus the 38% and 37%, respectively, in the comparable periods in 2021.

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



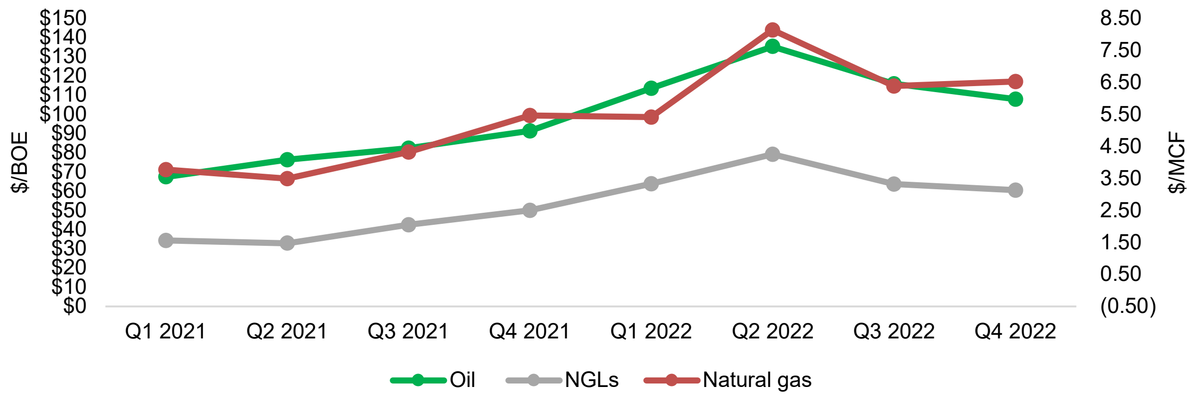
	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
P&NG Sales before royalties and financial instruments:						
Oil [5]	**63,570**	55,668	14	**240,913**	138,977	73
NGLs	**19,375**	14,983	29	**99,973**	46,083	117
Gas	**61,166**	48,047	27	**250,731**	125,086	100
P&NG Sales before marketing revenue [4][6]	**144,111**	118,698	21	**591,617**	310,146	91
Marketing revenue [1]	**8,609**	1,825	372	**21,741**	6,617	229
P&NG Sales	**152,720**	120,523	27	**613,358**	316,763	94
Cost of purchases [2]	**(8,509)**	(1,765)	382	**(21,438)**	(6,348)	238
P&NG Sales after cost of purchases [3][6]	**144,211**	118,758	21	**591,920**	310,415	91
Combined net realized price ($/BOE) [4][6]	**55.91**	50.01	12	**59.54**	40.52	47

(1) Marketing revenue includes the sale of third-party volumes related to the Company's oil blending operations and natural gas activities.
(2) Cost of purchases includes costs for the purchase of third-party volumes related to the Company's oil blending operations and natural gas activities.
(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) Combined net realized price ($/BOE) equals P&NG sales after cost of purchases divided by total production.
(5) "Oil" includes crude oil and field condensate.
(6) Refer to advisories regarding Non-GAAP and Other Financial Measures.

Petroleum and natural gas sales for the fourth quarter of 2022 was $152.7 million, an increase of 27% from $120.5 million from the fourth quarter of 2021. Petroleum and natural gas sales for the twelve months ending December 31, 2022 was $613.4 million, an increase of 94% from the comparable period in 2021. The increase in P&NG sales in 2022 from 2021 was due to a significant increase in the average benchmark oil and natural gas prices in 2022, and an increase in production in 2022.

Petroleum and natural gas sales of $152.7 million in the fourth quarter of 2022 increased 7% from $143.3 million in the third quarter of 2022. The increase quarter over quarter was primarily due a 9% increase in production which was offset by a 3% decrease in combined net realized prices.

Kelt Quarterly Realized Prices (1)



(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		
	2022	2021	%	**2022**	2021	%
Net realized prices (10)						
Oil ($/bbl) (9)	**107.88**	91.43	18	**117.18**	81.30	44
NGLs ($/bbl)	**60.54**	50.03	21	**67.64**	40.03	69
Gas ($/Mcf)	**6.52**	5.46	19	**6.63**	4.35	52
Combined ($/BOE)	**55.91**	50.01	12	**59.54**	40.52	47
Average benchmark prices						
Oil and NGLs						
WTI Cushing Oklahoma (US$/bbl) (1)	**82.77**	77.43	7	**94.80**	68.03	39
Mixed Sweet Blend Edmonton ("MSW") ($/bbl) (2)	**110.05**	93.26	18	**120.79**	80.29	50
Edmonton Pentane ($/bbl) (3)	**115.46**	100.14	15	**121.28**	85.55	42
Edmonton Butane ($/bbl) (3)	**54.90**	69.98	-22	**61.67**	48.49	27
Edmonton Propane ($/bbl) (3)	**39.07**	53.25	-27	**50.05**	41.78	20
Edmonton Ethane ($/bbl) (3)	**14.48**	12.08	20	**15.04**	9.67	56
Natural Gas						
NYMEX Henry Hub (US$/MMBtu) (6)	**5.55**	4.74	17	**6.38**	3.82	67
AECO 5A (CA$/MMBtu) (4)	**5.10**	4.65	10	**5.31**	3.62	47
Chicago Alliance, into Interstates (CA$/MMBtu) (5)	**7.20**	5.73	26	**7.88**	5.53	42
Dawn (CA$/MMBtu) (5)	**7.05**	5.85	21	**7.88**	4.54	74
Malin (CA$/MMBtu) (5)	**19.58**	6.76	190	**11.09**	4.95	124
Sumas (CA$/MMBtu) (5)	**19.48**	6.86	184	**10.70**	4.98	115
Station 2 (CA$/MMBtu) (7)	**3.18**	3.68	-14	**4.44**	3.29	35
Marcellus (TZ4 L300) (CA$/MMBtu) (5)	**6.88**	4.87	41	**7.33**	3.65	101
Average exchange rate (CA$/US$) (8)	**1.3582**	1.2601	8	**1.3019**	1.2536	4

(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) “Oil” includes crude oil and field condensate

(10) 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”.

Combined Net Realized Price

Kelt’s combined net realized price increased 12% to $55.91 per BOE and 47% to $59.54 per BOE in the three months and twelve months ended December 31, 2022, respectively, versus the comparable periods in 2021. The increase in the average realized price was primarily due to an increase in benchmark commodity prices in 2022.

Oil prices

WTI crude oil prices increased 7% for the quarter ended December 31, 2022 and increased 39% for the twelve months ended December 31, 2022 versus comparable periods in 2021. For the first six months of 2022, crude oil prices increased due to global sanctions on Russian exports, reduced capital directed towards production growth, and a reduction of global crude inventories as economies recovered following COVID-19 lockdowns. In the second half of 2022, benchmark crude oil prices decreased as the United States released significant amounts of crude oil from its strategic petroleum reserves, petroleum demand in China decreased due to COVID-19 lockdowns, and a slowdown in the global economy from rising interest rates resulted in a lower expectations for crude oil demand.

NGL prices

NGLs prices are impacted both by benchmark WTI prices, as well as localized market supply and demand issues.

For the three months and twelve months ended December 31, 2022, Kelt’s realized NGLs price increased 21% and 69%, respectively, as compared to the same periods in 2021. The increase was primarily due to an increase in benchmark WTI prices and regional improvements in condensate prices. Butane prices were higher in 2022 compared to 2021 primarily due to the rise in WTI prices. However, butane prices for the three months ended December 31, 2022 decreased from the comparable period in 2021 due to a spike in prices in the fourth quarter of 2021. Propane prices increased in 2022 from 2021 due to higher US and Canadian exports resulting in a reduction in domestic storage levels.

Natural gas prices

Kelt’s realized natural gas price increased by 19% to $6.52 per Mcf in the fourth quarter of 2022 and by 52% to $6.63 per Mcf for the twelve months ended December 31, 2022 versus comparable periods in 2021.

Canadian natural gas benchmark prices increased in 2022 due to a combination of increased Alberta demand, lower than average inventory levels, and high pipeline exports when compared to historical five-year averages.

American benchmark natural gas prices increased in the first six months of 2022 due to higher pipeline and LNG exports when compared to historical five-year averages. In the second half of 2022, higher US production, and the shut-in of a US LNG export facility, resulted in a decrease in eastern US benchmark natural gas. Western US benchmark natural gas prices remained elevated in the fourth quarter of 2022 due a lack of supply, and high demand.

For the twelve months ending December 31, 2022, Kelt sold 71% of its natural gas production at the AECO 5A and Station 2 indices, with the remainder primarily sold at the Dawn (20%), and Chicago (5%) indices.

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.

The table below summarizes realized and unrealized gains (losses) on risk management contracts:

(CA$ thousands, except as otherwise indicated)	Three months ended December 31 2022	2021	%	Year ended December 31 2022	2021	%
Realized gain (loss) on financial derivative contracts	**155**	(6,225)	102	**(60,633)**	(16,426)	269
Realized gain (loss) on natural gas embedded derivative	**4,124**	-	-	**4,124**	-	-
Total realized gain (loss) on derivative financial instruments	**4,279**	(6,225)	169	**(56,509)**	(16,426)	244
Unrealized gain on financial derivative contracts	**14,788**	17,007	-13	**15,146**	2,770	447
Unrealized gain on natural gas embedded derivative	**8,389**	-	-	**8,389**	-	-
Total unrealized gain on derivative financial instruments	**23,177**	17,007	36	**23,535**	2,770	750
Gain (loss) on derivative financial instruments	**27,456**	10,782	155	**(32,974)**	(13,656)	141
$ per BOE	**10.65**	4.54	135	**(3.31)**	(1.78)	86

Commodity price risk

Inherent to the business of producing oil and gas, the Company's net income 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 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 3, 2023, the following commodity price risk management contracts are outstanding:

Natural gas derivative contracts

Contract Type (2)	Notional Volume	Contract Price $/MMBtu	Remaining Term
AECO fixed price swap	5,000 GJ/d	CAD$4.00/GJ	Apr 23 – Oct 23
NYMEX-AECO 5A basis swap	20,000 MMBtu/d	NYMEX less USD$1.22	Jan 23 – Mar 23
NYMEX-AECO 7A basis swap	10,000 MMBtu/d	NYMEX less USD$0.98	Jan 23 – Mar 23
NYMEX-AECO 5A basis swap	10,000 MMBtu/d	Monthly AECO basis calculated at 30% of the floating monthly NYMEX price	Apr 23 – Oct 24
NYMEX-AECO 7A basis swap	25,000 MMBtu/d	NYMEX less USD$1.10	Apr 23 – Jul 23
NYMEX-AECO 7A basis swap	35,000 MMBtu/d	NYMEX less USD$1.18	Aug 23 – Oct 23
NYMEX-AECO 5A basis swap	15,000 MMBtu/d	NYMEX less USD$1.17	Apr 23 – Oct 23
NYMEX-AECO 5A basis swap	30,000 MMBtu/d	NYMEX less USD$1.10	Nov 24 – Oct 25
NYMEX-AECO 7A basis swap	5,000 MMBtu/d	NYMEX less USD$1.12	Nov 24 – Oct 25

Crude oil derivative contracts

Contract Type (1)(3)	Notional Volume	Contract Price $/bbl		Remaining Term
WTI-MSW basis swap	2,500 bbl/d	WTI less USD$2.70		Jan 23 – Jun 23
Costless Collars (1)	Notional Volume	Floor Price $/bbl	Ceiling Price $/bbl	Remaining Term
WTI costless collar	1,000 bbl/d	CAD$100	CAD$130	Jan 23 – Mar 23
WTI costless collar	1,000 bbl/d	CAD$102	CAD$128	Jan 23 – Mar 23

(1) West Texas Intermediate ("WTI")
(2) NYMEX Henry Hub ("NYMEX")
(3) Mixed Sweet Blend ("MSW")

In January 2023, the Company unwound 30,000 MMBtu/d of natural gas costless collar derivative contracts for February and March 2023 for proceeds of $8.06 million and unwound 20,000 MMBtu/d NYMEX fixed price swaps for February 2023 and 10,000 MMBtu/d NYMEX fixed price swaps for March 2023 for proceeds of $4.65 million.

Commencing in November 2022, the Company entered into a five-month natural gas supply agreement to deliver 7,458

GJ/d of gas to the Nova Inventory Transfer point. Under the terms of the agreement, the Company receives a price equal to the Floating Alberta Electric System Operator (“AESO”) Power Pool Price divided by the fixed heat rate of 16.95 GJ/MWH. It was determined that the agreement contained an embedded derivative, with the embedded derivative gains recorded under “Loss on derivative financial instruments” in the Consolidated Statement of Net Income and Comprehensive Net income of the consolidated annual financial statements as at December 31, 2022.

Natural gas embedded derivative

Contract Type (1)	Notional Volume	Contract Price	Remaining Term
Physical delivery contract	7,458 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.95 GJ/MWh	Jan 23 – Mar 23

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

In addition to the derivative contracts above, the Company has the following sales contracts for physical delivery:

Natural gas physical delivery contracts

Contract Type	Notional Volume	Contract Price	Remaining Term
Station 2 (physical) fixed price	9,900 GJ/d	CAD$5.78/GJ	Jan 23

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Company’s Credit Facility which is subject to a floating interest rate. Based on bank debt balance as of December 31, 2022 of $11.3 million, an increase (decrease) in the market rate of interest by 25 basis points would have an insignificant impact. As at March 3, 2023, 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 3, 2023, the following foreign exchange risk management contracts are outstanding:

Contract Type	Notional Volume	Contract Price	Remaining Term
CAD/USD swap	USD$3.0 million/month	$1.3625 CAD/USD	Jan 23 – Dec 23

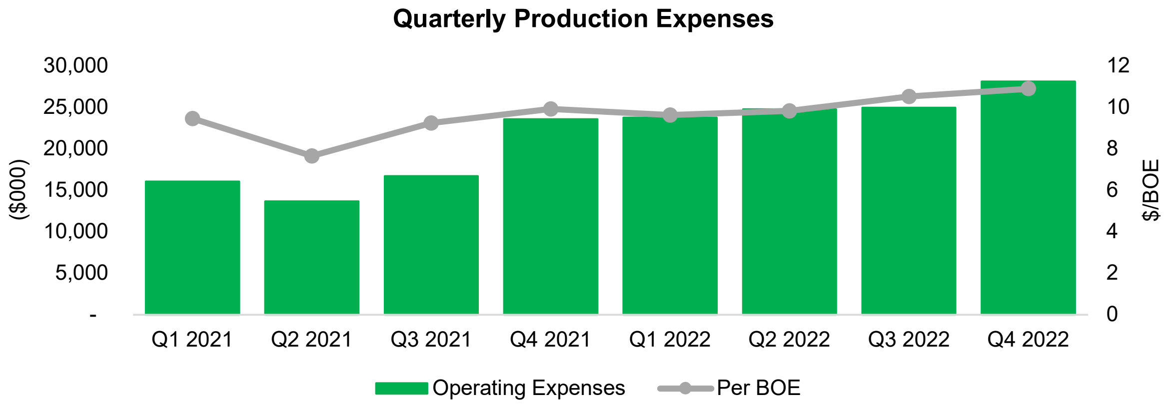
ROYALTIES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Royalties	**15,864**	9,901	60	**65,567**	27,414	139
Average royalty rate (1)	**11.0%**	8.3%	33	**11.1%**	8.8%	26
$ per BOE	**6.15**	4.17	47	**6.60**	3.58	84

(1) The average royalty rate is calculated based on total royalties as a percentage of “P&NG Sales, before marketing” 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 11.0% during the fourth quarter of 2022, compared to 8.3% during the fourth quarter of 2021. Kelt’s average royalty rate for the twelve months ended December 31, 2022 was 11.1% compared to 8.8% for the year ended December 31, 2021. A significant portion of the Company’s production in Alberta and British Columbia is initially subject to low royalty rates of 5% - 6%, prior to any additional credits. In 2022, a number of wells moved off the initial royalty rate and are now subject to higher royalty rates that are sensitive to commodity prices, resulting in an increase in the overall royalty rate in 2022. The higher royalty rates in 2022 were partially offset through the Company recognizing royalty infrastructure credits in British Columbia.

PRODUCTION EXPENSES

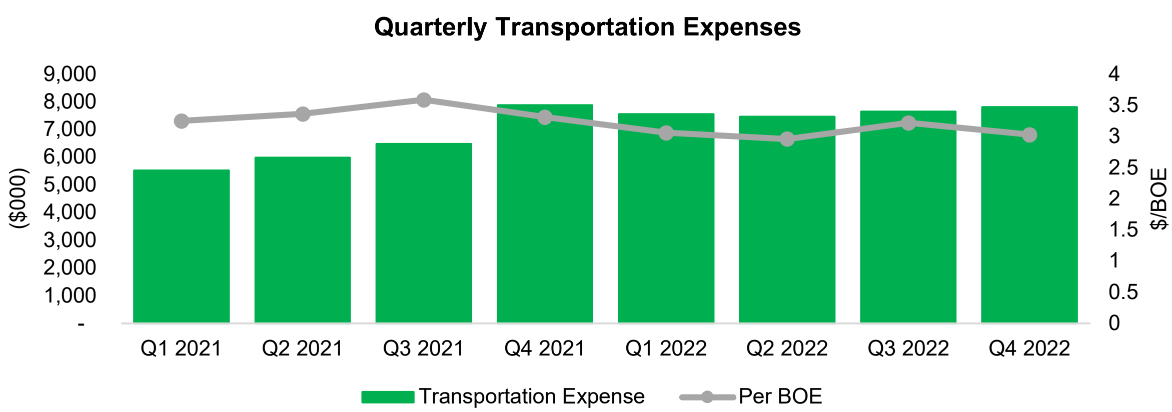


(CA$ thousands, except as otherwise indicated)	Three months ended December 31 **2022**	2021	%	Year ended December 31 **2022**	2021	%
Production expense	**28,116**	23,537	19	**101,566**	69,904	45
$ per BOE	**10.90**	9.91	10	**10.22**	9.13	12

Fourth quarter production expenses in 2022 increased 19% compared to the fourth quarter in 2021, and production expenses for the year ended December 31, 2022 increased 45% from the year ended December 31, 2021. The increase in the fourth quarter of 2022 was primarily related to higher production in 2022, along with higher electricity expenses and higher field maintenance costs, partially offset by lower trucking expenses. The increase in production expenses for the year ended December 31, 2022 compared to the prior year was primarily related to higher overall production in 2022, higher electricity expense, higher carbon tax expense and higher gas processing fees.

Production expenses per BOE increased 10% in the fourth quarter of 2022, and increased 12% for the year ended December 31, 2022 versus the comparable periods in 2021. The increase in the production expense per BOE was primarily due to higher field maintenance costs, higher electricity expense and higher carbon tax expense in 2022.

TRANSPORTATION EXPENSES



(CA$ thousands, except as otherwise indicated)	Three months ended December 31 2022	2021	%	Year ended December 31 2022	2021	%
Transportation expense [1]	**7,803**	7,872	-1	**30,467**	25,855	18
$ per BOE	**3.03**	3.31	-8	**3.06**	3.38	-9

(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 expenses averaged $3.03 per BOE during the fourth quarter of 2022, a decrease of 8% from $3.31 per BOE in the fourth quarter of 2021. Transportation expenses averaged $3.06 per BOE during the twelve months ending December 31, 2022, a decrease of 9% from $3.38 per BOE in the twelve months ended December 31, 2021. The decrease in transportation expense is due to Kelt proportionally increasing its exposure to AECO 5A and Station 2 indices in 2022, resulting in lower transportation costs on a BOE basis.

FINANCING EXPENSES

(CA$ thousands, except as otherwise indicated)	Three months ended December 31 2022	2021	%	Year ended December 31 2022	2021	%
Total interest expense	**581**	296	96	**1,460**	440	232
Accretion of decommissioning obligations	**721**	561	29	**2,451**	2,003	22
Total financing expense	**1,302**	857	52	**3,911**	2,443	60
Interest expense per BOE [1]	**0.23**	0.12	92	**0.15**	0.06	150
Average interest rates:						
Bank debt [2] [3]	**7.8%**	4.1%	90	**6.6%**	4.1%	61

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

(2) Average interest rate excludes fees on bank debt which include bank commitment, standby and guarantee letter fees.

Throughout 2022, the Company periodically drew on its credit facility and incurred standby fees, resulting in interest expense of $1.5 million.

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:

(CA$ thousands, except as otherwise indicated)	Three months ended December 31 2022	2021	%	Year ended December 31 2022	2021	%
Salaries and benefits	**4,010**	2,972	35	**12,287**	9,713	27
Other G&A expenses	**1,357**	1,043	30	**5,521**	3,745	47
Gross G&A expenses	**5,367**	4,015	34	**17,808**	13,458	32
Overhead recoveries	**(1,808)**	(1,129)	60	**(7,506)**	(4,207)	78
Net G&A expenses	**3,559**	2,886	23	**10,302**	9,251	11
Gross G&A ($ per BOE)	**2.08**	1.69	23	**1.79**	1.76	2
Net G&A ($ per BOE)	**1.38**	1.22	13	**1.04**	1.21	-14

Net G&A expenses averaged $1.38 per BOE during the fourth quarter of 2022, an increase of 13% compared to $1.22 per BOE during the fourth quarter of 2021. For the twelve months ended December 31, 2022, net G&A expenses averaged $1.04 per BOE which decreased by 14% compared to $1.21 per BOE during same period in 2021. The decrease in net G&A expenses per BOE was primarily due to higher overhead recoveries and production increasing at a higher rate than G&A expense.

G&A expenses are reported net of overhead recoveries; however, Kelt does not capitalize any direct G&A expenses.

SHARE BASED COMPENSATION ("SBC")

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Stock options	**1,679**	793	112	**5,902**	3,054	93
Restricted share units ("RSUs")	**308**	214	44	**1,112**	1,162	-4
Total SBC expense	**1,987**	1,007	97	**7,014**	4,216	66
$ per BOE	**0.77**	0.42	83	**0.71**	0.55	29

The increase in SBC expense for the three and twelve months ended December 31, 2022 compared to the same periods in 2021 is primarily due the higher Black-Scholes value associated with recent options granted.

As at December 31, 2022, stock options and RSUs outstanding represent 5.9% of total shares outstanding (December 31, 2021 – 6.0%).

EXPLORATION AND EVALUATION ("E&E") EXPENSES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Exploration and evaluation expense	**14,438**	709	1936	**14,484**	928	1461
$ per BOE	**5.60**	0.30	1767	**1.46**	0.12	1117

E&E expense was $14.4 million for the quarter ended December 31, 2022 and $14.5 million in the year ended December 31, 2022. During the fourth quarter of 2022, the Company expensed $14.2 million of exploratory drilling costs for two exploration wells. The two exploration wells were determined to be not technically feasible and proved reserves could not be established after the second well was completed and tested in the fourth quarter of 2022.

DEPLETION, DEPRECIATION AND IMPAIRMENT REVERSAL

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Depletion and depreciation	**28,182**	26,936	5	**116,183**	91,251	27
Impairment reversal	**-**	-	-	**-**	(70,130)	-100
Total	**28,182**	26,936	5	**116,183**	21,121	450
Depletion and depreciation ($/BOE)	**10.93**	11.34	-4	**11.69**	11.91	-2
Impairment reversal ($/BOE)	**-**	-	-	**-**	(9.16)	-100

Depletion and depreciation expense of $28.2 million for the quarter ended December 31, 2022 increased by 5% from $26.9 million in the comparable period in 2021. Depletion and depreciation expense for the year ended December 31, 2022 decreased 27% as compared to the prior year. On a per BOE basis, the depletion and depreciation expense per BOE decreased slightly in 2022, due to an increase in reserve additions in 2022.

In the second quarter of 2021, an impairment reversal test was performed on the Alberta CGU based on increased forward commodity price forecasts and an increase in the Company's market capitalization. It was determined that the recoverable amount of the Alberta CGU was in excess of its carrying value resulting in an impairment reversal of $70.1 million (before-tax).

Based on its assessment as of December 31, 2022, the Company determined that there were no potential indicators of impairment for the Alberta CGU and BC CGU and there are no previous impairments available for reversals.

INCOME TAXES

	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Deferred income tax expense	**16,412**	1,932	749	**51,441**	21,436	140
Net income before taxes	**70,650**	54,928	29	**210,199**	135,692	55
Effective tax rate	**23.2%**	3.5%	560	**24.5%**	15.8%	55

Kelt's consolidated combined federal and provincial statutory tax rate averaged 23.9% and 23.0% during the three months ended December 31, 2022 and 2021, respectively. The Company is not expected to have any cash income taxes payable in 2023.

The Company's consolidated tax pools are estimated to be approximately $768.4 million as of December 31, 2022, a decrease of 1% from December 31, 2021 as summarized in the table below.

(CA$ thousands, except as otherwise indicated)	Rate	**December 31 2022**	December 31 2021	%
Canadian oil and gas property expenses (COGPE)	10-15%	**66,848**	73,107	-9
Canadian development expenses (CDE)	30-45%	**192,737**	125,246	54
Canadian exploration expenses (CEE)	100%	**-**	22,538	-100
Undepreciated capital cost (1) (UCC)	25-37.5%	**228,487**	196,613	16
Share and debt issue costs	5 years	**8**	240	-97
Non-capital losses (2) (NCL)	100%	**280,308**	356,439	-21
Estimated tax deductions available, end of period		**768,388**	774,183	-1

(1) The majority of the Company's undepreciated capital cost deductions relate to Class 41 assets, which are deductible at a rate of 25-37.5% per year.
(2) The Company's non-capital losses expire in years 2033 to 2041.

ADJUSTED FUNDS FROM OPERATIONS

The following table provides a continuity of income and expenses included in the Company's calculation of operating netback and adjusted funds from operations generated during the three months and year ended December 31, 2022 and 2021 respectively.

THREE MONTHS ENDED DECEMBER 31	Amount			$/BOE		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Petroleum and natural gas sales	**152,720**	120,523	27	**59.21**	50.75	17
Cost of purchases	**(8,509)**	(1,765)	382	**(3.30)**	(0.74)	346
Realized loss on financial instruments (1)	**4,279**	(6,225)	169	**1.66**	(2.62)	-163
Royalties	**(15,864)**	(9,901)	60	**(6.15)**	(4.17)	47
Revenue, after royalties and financial instruments	**132,626**	102,632	29	**51.42**	43.22	19
Production expense	**(28,116)**	(23,537)	19	**(10.90)**	(9.91)	10
Transportation expense	**(7,803)**	(7,872)	-1	**(3.03)**	(3.31)	-8
Operating netback (2)	**96,707**	71,223	36	**37.49**	30.00	25
Financing expense (3)	**(581)**	(296)	96	**(0.23)**	(0.12)	92
G&A expense	**(3,559)**	(2,886)	23	**(1.38)**	(1.22)	13
Gain on foreign exchange	**219**	95	131	**0.09**	0.04	125
Other income/expense (5)	**65**	19	242	**0.03**	0.01	200
Adjusted funds from operations (2)	**92,851**	68,155	36	**36.00**	28.71	25
Basic ($ per common share) (4)	**0.48**	0.36	33			
Diluted ($ per common share) (4)	**0.47**	0.35	34			

(1) Includes realized gains (losses) on commodity price and foreign exchange derivatives.

(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.

(5) Excludes non cash provisions

YEAR ENDED DECEMBER 31	Amount			$/BOE		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Petroleum and natural gas sales	**613,358**	316,763	94	**61.70**	41.35	49
Cost of purchases	**(21,438)**	(6,348)	238	**(2.16)**	(0.83)	160
Realized gain (loss) on financial instruments (1)	**(56,509)**	(16,426)	244	**(5.68)**	(2.14)	165
Royalties	**(65,567)**	(27,414)	139	**(6.60)**	(3.58)	84
Revenue, after royalties and financial instruments	**469,844**	266,575	76	**47.26**	34.80	36
Production expense	**(101,566)**	(69,904)	45	**(10.22)**	(9.13)	12
Transportation expense	**(30,467)**	(25,855)	18	**(3.06)**	(3.38)	-9
Operating netback (2)	**337,811**	170,816	98	**33.98**	22.29	52
Financing expense (3)	**(1,460)**	(440)	232	**(0.15)**	(0.06)	150
G&A expense	**(10,302)**	(9,251)	11	**(1.04)**	(1.21)	-14
Gain on foreign exchange	**788**	15	5153	**0.08**	-	-
Other income/expense (5)	**155**	254	-39	**0.02**	0.03	-33
Adjusted funds from operations (2)	**326,992**	161,394	103	**32.89**	21.05	56
Basic ($ per common share) (4)	**1.71**	0.85	101			
Diluted ($ per common share) (4)	**1.67**	0.85	96			

(1) Includes realized gains (losses) on commodity price and foreign exchange derivatives.

(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.

(5) Excludes non cash provisions

During the three months ended December 31, 2022, adjusted funds from operations of $92.9 million ($0.47 per share, diluted) increased by 36% from $68.2 million ($0.35 per share, diluted) in the fourth quarter of 2021. During the year ended December 31, 2022, adjusted funds from operations of $327.0 million ($1.67 per share, diluted) increased by 103% from $161.4 million ($0.85 per share, diluted) during the year ended December 31, 2021. The increase in adjusted funds from operations for both the three and twelve months ended December 31, 2022 compared to the same periods in 2021 is primarily attributed to an increase in petroleum and natural gas sales of 27% and 94%, respectively.

NET INCOME AND COMPREHENSIVE INCOME

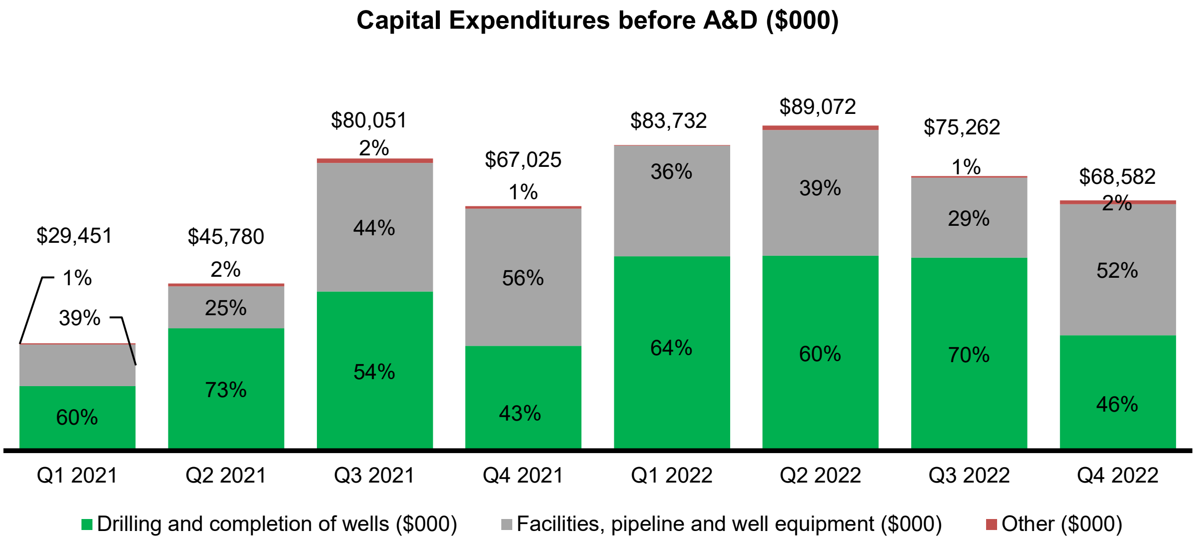
	Three months ended December 31			Year ended December 31		
(CA$ thousands, except as otherwise indicated)	**2022**	2021	%	**2022**	2021	%
Net income and comprehensive income	**54,238**	52,996	2	**158,758**	114,256	39
$ per common share, basic	**0.28**	0.28	-	**0.83**	0.61	36
$ per common share, diluted (1)	**0.28**	0.28	-	**0.81**	0.60	35
$ per BOE	**21.05**	22.33	-6	**15.96**	14.90	7
Wtd avg. shares outstanding, basic (000s)	**191,812**	189,134	1	**191,101**	188,800	1
Wtd avg. shares outstanding, diluted (000s) (1)	**195,828**	192,676	2	**195,456**	190,807	2

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

Kelt reported net income of $54.2 million ($0.28 per common share, diluted) for the three months December 31, 2022, an increase of $1.2 million from $53.0 million ($0.28 per common share, diluted) in the same three month period of 2021. The increase in net income is primarily due to a $24.7 million increase in adjusted funds from operations, and higher unrealized gains on derivatives of $6.2 million in 2022 which was partially offset by higher deferred income tax expense of $14.5 million in 2022, and higher exploration and evaluation expenses of $13.7 million in 2022.

Kelt reported net income of $158.8 million ($0.81 per common share, diluted) for the year ended December 31, 2022, an increase of $44.5 million from $114.3 million ($0.60 per common share, diluted) in the same period of 2021. The increase in net income is primarily due to a $165.6 million increase in adjusted funds from operations in 2022 and higher unrealized gains on derivatives of $20.8 million in 2022, which was partially offset by an impairment reversal and lower depletion and depreciation in 2021 of $95.1 million, higher deferred income tax expense of $30.0 million in 2022 and higher exploration and evaluation expenses of $13.6 million in 2022.

INVESTING ACTIVITIES



CAPITAL EXPENDITURES

The Company's capital expenditures, 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)	**2022**	2021	%	**2022**	2021	%
Capital expenditures:						
Lease acquisition and retention	**465**	559	-17	**1,509**	1,872	-19
Geological and geophysical	**531**	78	581	**623**	119	424
Drilling and completion of wells	**31,558**	28,753	10	**191,026**	123,508	55
Facilities, pipeline and well equipment	**35,928**	37,562	-4	**122,662**	95,721	28
Corporate assets	**100**	73	37	**828**	1,087	-24
Capital expenditures, before A&D (1)	**68,582**	67,025	2	**316,648**	222,307	42
Property acquisitions	**62**	36	72	**3,462**	252	1274
Property dispositions	**(50)**	57	-188	**(2,570)**	(9,048)	-72
Capital expenditures, net of A&D (1)	**68,594**	67,118	2	**317,540**	213,511	49

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

Capital expenditures, before A&D, increased 2% in the fourth quarter of 2022 and increased 42% from the year ended December 31, 2022 versus the comparable period in 2021.

In the fourth quarter of 2022, drilling and completion costs of $31.6 million included the drilling of 3.0 gross and net wells and completion of 7 gross wells (6.0 net wells). Kelt's facility, pipeline and well equipment spending in the fourth quarter of 2022 of $35.9 million focused on well equipment and facility optimization and upgrade work.

For the twelve months ended December 31, 2022, drilling and completion costs of $191.0 million included the drilling of 31 gross wells (28.4 net wells) and completion of 35 gross wells (32.1 net wells). The wells drilled included 18 gross (17 net) Montney wells, 12 gross (10.4 net) Charlie Lake wells, and one exploratory well.

Kelt's facility, pipeline and well equipment spending in 2022 included $122.7 million focused on well equipment, pipeline and facility optimization and upgrade work. Kelt added additional gas compression and enlarged its oil facilities at Pouce Coupe and Spirit River, and built various oil and gas gathering pipelines at Wembley/Pipestone. Capital expenditures for 2022 also included the purchasing of equipment and pipe in order to facilitate a timely execution of the Company's 2023 drilling program.

	Three months ended December 31			Year ended December 31		
Gross Wells	**2022**	2021	%	**2022**	2021	%
Drilling	**3**	5	-40	**31**	21	48
Completion	**7**	3	133	**35**	23	52
Service	**-**	-	-	**-**	2	-100

	Three months ended December 31			Year ended December 31		
Net Wells	**2022**	2021	%	**2022**	2021	%
Drilling	**3.0**	4.7	-36	**28.4**	20.7	37
Completion	**6.0**	3.0	100	**32.1**	23.0	40
Service	**-**	-	-	**-**	2.0	-100

LAND HOLDINGS

The table below sets-out Kelt's significant Montney land holdings across British Columbia and Alberta as at December 31, 2022.

MONTNEY RIGHTS	**Net Acres**	Net Sections
British Columbia	**193,607**	303
Alberta	**150,667**	235
Total	**344,274**	538
CHARLIE LAKE RIGHTS		
Alberta	**88,447**	138

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.

As of December 31, 2022 the Company had a $100.0 million demand and revolving term facility ("the Credit Facility") with a syndicate of financial institutions. As at December 31, 2022, $11.3 million was drawn under the Credit Facility, with outstanding letters of credit of $2.0 million.

The Credit Facility, which is subject to semi-annual redeterminations, may be extended annually at Kelt's option, 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 and the Company is in compliance with all covenants, representations and warranties. 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 $800 million demand debenture with a floating charge over all the Company's assets.

	December 31, 2022	December 31, 2021
Bank debt	**11,300**	1,150
Accounts payable and accrued liabilities	**83,288**	72,453
Cash and cash equivalents	**(125)**	(719)
Accounts receivable and accrued sales	**(81,075)**	(42,584)
Prepaid expenses and deposits	**(3,599)**	(2,080)
Net debt (1)	**9,789**	28,220
Annualized quarterly adjusted funds from operations (1)(2)	**371,404**	272,620
Net debt to annualized quarterly adjusted funds from operations ratio (1)	**0.0**	0.1

(1) Refer to advisories regarding Capital Management Measures.

(2) Adjusted funds from operations are annualized based on the most recent quarter's adjusted funds from operations.

The Company monitors its capital structure and short-term financing requirements using a net debt to annualized quarterly adjusted funds from operations ratio, which is a non-GAAP financial measure. Kelt targets a net debt to annualized quarterly 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. To adjust its capital structure, 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, 2022:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	83,288	-	-	**83,288**
Derivative financial instruments	1,414	-	-	**1,414**
Lease liability	505	543	-	**1,048**
Bank debt and estimated interest (1)	746	11,300	-	**12,046**
Total	**85,953**	**11,843**	**-**	**97,796**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 6.6% for the year ended December 31, 2022, applied to the principal balance outstanding as at that date.

COMMITMENTS

As of December 31, 2022, the Company is committed to future payments under the following agreements:

	2023	2024	2025	2026	2027	Thereafter
Firm processing commitments	18,969	27,700	39,754	39,504	38,812	261,361
Firm transportation commitments	28,887	28,414	26,638	26,997	23,404	48,711
Total commitments	**47,856**	**56,114**	**66,392**	**66,501**	**62,216**	**310,072**

In 2022, Kelt entered into two gas processing agreements with third party midstream companies. The third party gas processing plants are expected to become operational in late 2023 or early 2024 and in the fourth quarter of 2024, with a total expected increase of approximately $300 million to Kelt's future payments under these agreements.

SHARE INFORMATION

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2022 there were 192.0 million common shares issued and outstanding. There are no preferred shares issued or outstanding.

At December 31, 2022, officers, directors, and employees have been granted options to purchase 10.5 million common shares of the Company at an average exercise price of $3.71 per common share. In addition, there are 0.9 million

RSUs outstanding.

The following table outlines Kelt's common share trading activity during 2022 and 2021:

SHARE TRADING ACTIVITY (KEL)	YTD 2022	YTD 2021
High ($)	**8.32**	5.44
Low ($)	**4.67**	1.74
Close ($)	**5.01**	4.82
Volume traded (thousands)	**125,751**	156,801
Value traded ($ thousands)	**759,986**	501,057
Weighted average trading price ($)	**6.04**	3.20

RELATED PARTY TRANSACTIONS

The Company has engaged a law firm where the corporate secretary of Kelt is a partner, and Kelt 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, 2022, the Company incurred $0.4 million (December 31, 2021 – $0.2 million) in disbursements to related parties.

OFF-BALANCE SHEET TRANSACTIONS

The Company did not engage in any off-balance sheet transactions during the periods ended December 31, 2022 and 2021.

RESERVES

Kelt retained Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator to prepare a report on its oil and gas reserves (the "Sproule 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, 2022 and at December 31, 2021 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). The Sproule Report is effective as of December 31, 2022.

At December 31, 2022, Kelt's proved plus probable reserves were 340.8 million BOE, up 34% from 254.1 million BOE at December 31, 2021. The Company's net present value of proved plus probable reserves at December 31, 2022, discounted at 10% before tax, was $3.4 billion, an increase of 60% from $2.1 billion at December 31, 2021. Sproule's forecasted commodity prices for 2023 used to determine the present value of the Company's reserves at December 31, 2022, are US$86.00 per barrel for WTI oil and CAD$4.11 per GJ for AECO-C gas.

At December 31, 2022, the weighting of proved plus probable reserves was 38% oil/NGLs and 62% natural gas. At December 31, 2021, the weighting of proved plus probable reserves was 41% oil/NGLs and 59% natural gas.

The following table outlines a summary of the Company's reserves volumes at December 31, 2022:

SUMMARY OF RESERVE VOLUMES	Crude Oil (mbbls)	Liquids(1) (mbbls)	Natural Gas (mmcf)	Combined (mBOE)	FDC Costs ($ thousands)
Proved developed producing	10,052	9,783	247,362	**61,062**	**-**
Proved developed non-producing	408	492	7,338	**2,123**	**5,882**
Proved undeveloped	20,385	31,135	464,211	**128,888**	**1,204,243**
Total Proved	**30,845**	**41,410**	**718,911**	**192,073**	**1,210,125**
Probable additional	22,019	35,206	549,020	**148,728**	**834,029**
Total Proved plus Probable	**52,864**	**76,616**	**1,267,931**	**340,801**	**2,044,154**

(1) "Liquids" include field condensate and NGLs.

CHANGE IN RESERVES – YEAR OVER YEAR (mBOE)	**December 31 2022**	December 31 2021	% Change
Proved developed producing	**61,062**	43,854	39
Proved developed non-producing	**2,123**	2,083	2
Proved undeveloped	**128,888**	88,155	46
Total Proved	**192,073**	134,092	43
Probable additional	**148,728**	120,057	24
Total Proved plus Probable	**340,801**	254,149	34

The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2022:

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$/CA$
2023	86.00	110.67	5.00	4.11	0.75
2024	84.00	101.25	4.50	4.12	0.80
2025	80.00	96.18	4.25	3.79	0.80
2026	81.60	98.10	4.34	3.87	0.80
2027	83.23	100.06	4.42	3.94	0.80
Five year average	**82.97**	**101.25**	**4.50**	**3.97**	**0.79**

The following table summarizes the net present value of the Company's reserves (before tax) as at December 31, 2022:

NET PRESENT VALUE (BEFORE TAX) *(CA$ millions)*	Undiscounted	NPV 5% BT	NPV 10% BT
Proved developed producing	1,018	945	842
Proved developed non-producing	44	36	30
Proved undeveloped	2,239	1,493	1,055
Total Proved	**3,301**	**2,474**	**1,927**
Probable additional	3,120	2,080	1,503
Total Proved plus Probable	**6,421**	**4,554**	**3,430**

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 2022**	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Petroleum and natural gas sales	**152,720**	143,254	178,938	138,446	120,523	75,761	60,644	59,835
Cash provided by operating activities	**63,742**	85,104	91,623	65,553	52,056	46,547	34,529	26,582
Adjusted funds from operations (1)	**92,851**	65,189	94,783	74,169	68,155	36,336	29,452	27,451
Per share – basic ($/common share) (1)	**0.48**	0.34	0.50	0.39	0.36	0.19	0.16	0.15
Per share – diluted ($/common share) (1)	**0.47**	0.33	0.48	0.38	0.35	0.19	0.15	0.14
Net income and comprehensive income	**54,238**	23,089	70,711	10,720	52,996	3,752	54,654	2,854
Per share – basic ($/common share)	**0.28**	0.12	0.37	0.06	0.28	0.02	0.29	0.02
Per share – diluted ($/common share)	**0.28**	0.12	0.36	0.06	0.28	0.02	0.29	0.02
Capital expenditures, net of A&D (1)	**68,594**	76,181	89,072	83,693	67,118	71,162	45,786	29,446
Total assets	**1,128,104**	1,078,619	1,035,372	967,119	913,497	872,212	842,454	775,033
Bank debt	**11,300**	-	-	-	1,150	-	-	-
Net debt (1)	**9,789**	33,537	23,117	34,685	28,220	28,174	(6,696)	(24,303)
Shareholders' equity	**901,424**	845,103	818,734	739,673	722,724	668,561	663,284	607,285
Average daily production (BOE/d)	**28,036**	25,791	27,713	27,413	25,815	19,621	19,592	18,860
Combined net realized price ($/BOE) (1)(2)	**57.57**	48.97	58.50	49.96	47.39	38.33	31.49	33.07
Operating netback ($/BOE) (1)	**37.49**	28.19	38.52	31.26	30.00	21.10	17.68	17.67
Operating netback % of combined net realized price (2)	**65%**	58%	66%	63%	63%	55%	56%	53%

(1) Refer to advisories regarding *"Non-GAAP and Other Financial Measures"*.
(2) In this table, combined net realized prices are after financial instruments.

Following the unprecedented reduction in global crude oil demand as a result of the COVID-19 pandemic, global crude oil prices steadily increased in 2021 due to increasing demand, OPEC+ production curtailments, and lower levels of capital investment in both OPEC+ and non-OPEC nations. In 2022, crude oil prices remained strong and were impacted by a number of factors including the Russian and Ukrainian conflict, the US releasing crude oil from its strategic reserves, continued COVID-19 lockdowns in China, and rising lending rates impacting global demand of crude oil.

North American benchmark natural gas prices increased in the first nine months of 2022 due to record LNG exports, inventory levels remaining below average storage levels and increasing North American demand. However increasing US and Canadian production in 2022, and the shut-in of a US LNG export facility in June 2022 resulted in rising North American inventory levels, and a decrease in eastern North American benchmark natural gas prices in the fourth quarter. Western US benchmark natural gas prices remained elevated in the fourth quarter of 2022 due high demand.

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.sedar.com

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)	**2022**	2021	2020
Petroleum and natural gas sales	**613,358**	316,763	207,156
Cash provided by operating activities	**306,022**	159,714	59,279
Adjusted funds from operations (1)	**326,992**	161,394	58,832
Per share – basic ($/common share)	**1.71**	0.85	0.31
Per share – diluted ($/common share)	**1.67**	0.85	0.31
Net income (loss) and comprehensive income (loss)	**158,758**	114,256	(324,807)
Per share – basic ($/common share)	**0.83**	0.61	(1.73)
Per share – diluted ($/common share)	**0.81**	0.60	(1.73)
Capital expenditures, net of A&D (1)	**317,540**	213,511	(353,957)
Total assets	**1,128,104**	913,497	759,987
Bank debt	**11,300**	1,150	-
Net debt (1)	**9,789**	28,220	(27,655)
Shareholders' equity	**901,424**	722,724	603,684
Average daily production (BOE/d)	**27,236**	20,987	24,992
Combined net realized price ($/BOE) (1)(2)	**53.86**	38.38	22.72
Operating netback ($/BOE) (1)	**33.98**	22.29	8.41
Operating netback as a % of combined net realized price (2)	**63%**	58%	37%

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

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

OUTLOOK AND GUIDANCE

The table below compares the Company's previously forecasted assumptions and expected financial and operating results for 2022 to actual 2022 results:

(CA$ millions, except as otherwise indicated)	**2022 Actuals**	2022 Budget	% Change
Average Production			
Oil and NGLs (bbls/d)	**9,689**	9,900 – 10,500	-2 to -8
Gas (MMcf/d)	**105.3**	105.6 – 108.0	0 to -3
Combined (BOE/d)	**27,236**	27,500 – 28,500	-1 to -4
Forecasted Average Commodity Prices			
WTI oil price (US$/bbl)	**94.80**	94.50	-
Canadian Light Sweet ($/bbl)	**120.79**	120.00	1
NYMEX natural gas price (US$/MMBtu)	**6.38**	6.40	-
AECO natural gas price ($/GJ)	**5.04**	4.90	-3
Average Exchange Rate (US$/CA$)	**0.7681**	0.7692	-

(CA$ millions, except as otherwise indicated)	**2022 Actuals**	2022 Updated Guidance	% Change
Capital Expenditures			
Drilling & Completions	**191.0**	183.0	4
Equipment, Facilities & Pipeline Infrastructure	**122.7**	112.0	10
Land, Seismic & Asset Acquisitions, net of Property Dispositions	**3.9**	5.0	-23
Capital Expenditures, net of A&D (1)	**317.5**	300.0	6
Petroleum and natural gas sales	**613.4**	617.0	-1
Adjusted funds from operations (1)	**327.0**	325.0	1
Per common share, diluted (1)	**1.67**	1.66	1
Net debt (surplus), at year end (1)	**9.8**	(5.0)	-
Weighted average common shares outstanding (millions) (1)	**191.1**	191.1	-

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

Kelt's financial results for the year ended December 31, 2022 was largely within its previous guidance, apart from capital expenditures net of A&D and net debt. Capital expenditures net of A&D was $317.5 million in 2022, 6% higher than the forecasted amount of $300.0 million, resulting in net debt as of December 31, 2022 of $9.8 million compared to the previous guidance of a $5.0 million net surplus. Capital expenditures, net of A&D increased primarily due to the advance purchasing of equipment and pipe to facilitate the execution of the Company's 2023 drilling program, and higher than forecasted drilling, completion, and facility infrastructure costs.

2023 BUDGET

The Company's Board of Directors has approved a revision to the Company's 2023 budget due to 32% reduction of the forecasted 2023 NYMEX and AECO 5A natural gas benchmark prices. As a result of the decrease in forecasted natural gas prices, the Company's 2023 capital expenditure budget has been reduced to $285.0 million in 2023, a decrease of 8% from the previous capital expenditure budget of $310.0 million. The number of expected drills and completes for the year has been reduced, with the Company now forecasting to drill 27 gross wells (26.0 net wells) and completing 29 gross wells (28.0 net wells). The Company's financial position is expected to remain strong with forecasted net debt of $14.8 million at the end of 2023, or less than 0.1 times estimated 2023 adjusted funds from operations.

Forecasted average production for 2023 is estimated to be approximately 32,000 – 34,000 BOE per day, a decrease of 3% from the previous 2023 forecasted production budget, and an increase of 17% to 25% from the fourth quarter of 2022. Kelt's forecasted 2023 production is expected to be weighted approximately 37% oil and NGLs and 63% natural gas.

Forecasted WTI crude oil price for 2023 remains at US$78.00 per barrel, representing a decrease of 18% from 2022 prices. Canadian Light Sweet is forecasted to average $99.73 per barrel in 2023, a decrease of 17% over 2022 prices. Natural gas prices are forecast to average $2.94 per GJ for AECO and US$3.39 per MMbtu for NYMEX in 2023, a decrease of 32% from previously forecasted prices, and a decrease of 42% and 47%, respectively over 2022 prices.

Using the revised commodity price forecasts for 2023, Kelt is forecasting 2023 adjusted funds from operations of $285.0 million ($1.44 per common share, diluted), down 16% from its previous forecast. Kelt estimates a net debt of $14.8 million at the end of December 31, 2023.

A 10% increase/decrease in the Company's forecasted oil/NGLs price for 2023 would increase/decrease forecasted adjusted funds from operations by approximately $24.6 million. A 10% increase/decrease in the Company's average gas price forecasted for 2023 would increase/decrease adjusted funds from operations by approximately $13.5 million.

The table below outlines the Company's updated forecast for 2023 with a comparison to the previously announced guidance included in Kelt's press release dated November 10, 2022 and comparison to 2022 actuals:

(CA$ millions, except as otherwise indicated)	Current 2023 Budget	Previous 2023 Guidance (Nov 10, 2022)	% Change to Current 2023 Budget	2022 Actuals	Current 2023 Budget % Change to 2022 Actuals
Average Production					
Oil and NGLs (bbls/d)	**11,700 – 12,900**	11,700 – 12,900	-	**9,689**	21 – 33
Gas (mmcf/d)	**121.8 – 126.6**	127.8 – 132.6	-5	**105.3**	16 – 20
Combined (BOE/d)	**32,000 – 34,000**	33,000 – 35,000	-3	**27,236**	17 – 25
Forecasted Average Commodity Prices					
WTI oil price (US$/bbl)	**78.00**	78.00	-	**94.80**	-18
Canadian Light Sweet ($/bbl)	**99.73**	99.90	-	**120.79**	-17
NYMEX natural gas price (US$/MMBtu)	**3.39**	5.00	-32	**6.38**	-47
AECO natural gas price ($/GJ)	**2.94**	4.30	-32	**5.04**	-42
Average Exchange Rate (US$/CA$)	**0.7513**	0.7407	1	**0.7681**	-2
Capital Expenditures					
Drilling & completions	**195.0**	220.0	-11	**191.0**	2
Equipment, Facilities & Pipeline Infrastructure	**70.0**	70.0	-	**122.7**	-43
Land, Seismic & Asset Acquisitions, net of Property Dispositions	**20.0**	20.0	-	**3.9**	419
Capital Expenditures, net of A&D (1)	**285.0**	310.0	-8	**317.5**	-10
Petroleum and natural gas sales	**530.1**	607.0	-13	**613.4**	-14
Adjusted funds from operations (1)	**285.0**	338.0	-16	**327.0**	-13
Per common share, diluted (1)	**1.44**	1.71	-16	**1.67**	-14
Net debt (1)	**14.8**	(28.0)	153	**9.8**	51
Weighted average common shares outstanding (millions) (1)	**192.3**	192.2	-	**191.1**	1

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

Kelt expects to maintain a strong balance sheet, giving the Company the ability to take advantage of opportunities as they arise. The Company’s capital expenditure program is also flexible, with the ability to increase or decrease expenditures into the future if the economic environment changes.

Changes in forecasted commodity prices and variances in production estimates can have a significant impact on estimated adjusted funds from operations and profit. Please refer to the advisories regarding forward-looking statements and to the cautionary statement below.

The information set out herein is “financial outlook” within the meaning of applicable securities laws. See the “Advisory regarding forward-looking statements” section below for additional information.

SIGNIFICANT JUDGMENTS AND ESTIMATES

The significant accounting policies applied by the Company are disclosed in note 2 of the consolidated annual financial statements as at and for the year ended December 31, 2022. 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.

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, in accordance with the Canadian Oil and Gas Evaluation Handbook (“COGEH”).

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 Company’s 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. For the Company, 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 estimated proved reserves, which are used, in part, to determine a project’s technical feasibility and commercial viability and could be impacted by a shift in demand as global energy markets transition to a lower carbon-based economy. Refer to additional information regarding E&E assets in note 5 of the consolidated annual financial statements.

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, 2022, 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. Refer to specific information regarding the Company’s CGUs in note 6 of the consolidated annual financial statements.

Impairment of non-financial assets

Significant judgment is required to assess the Company’s non-financial assets, namely E&E and PP&E, for impairment or potential reversals of previously recorded impairment. 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. In addition, judgment is required to assess whether a previously recognized impairment for an asset no longer exists or has decreased.

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.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require significant judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the acquisition equation. Future profit (loss) can be affected as a result of changes in future depletion and depreciation or impairment.

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 can fluctuate 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 8 of the consolidated annual 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, the expected timing of settlement is estimated to be between six and ten years, unless the timing to abandon and reclaim a specific well site or facility is known based on budgeted expenditures.

Deferred income taxes

The Company follows the liability method 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. The provision for deferred income taxes also includes the following significant judgments of management.

Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings, and are reduced to the extent it is no longer probable that the related tax benefit will be realized. The Company's non-capital losses expire in years 2033 to 2041.

Share based compensation

The Company uses the fair value method of accounting for its long-term incentive plans, which include an Incentive Stock Option Plan and a Restricted 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 Company uses the Black-Scholes option pricing model 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.

The fair value of restricted share units is estimated based on the volume weighted average trading price ("VWAP") on the TSX over three trading days immediately prior to the date of grant. Judgment is also required to estimate the rate of forfeiture, or number of restricted share units that will ultimately vest. These assumptions used by the Company are discussed in note 10 of the consolidated annual financial statements.

Derivative financial instruments

The Company applies judgement in assessing and determining when an embedded derivative exists within a host contract, if the embedded derivative is closely related to the host contract, and the inputs used to fair value an embedded derivative if it is not closely related to the host contract, which would include forecasted benchmark commodity prices.

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, 2022 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 interim period from October 1, 2022 to December 31, 2022 and year ended December 31, 2022. The CEO and the CFO have evaluated the effectiveness of Kelt's internal controls over financial reporting as at December 31, 2022 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;
- 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, ARO, 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 ability to 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 Company incurred $2.1 million in carbon tax expense in 2022 ($0.2 million in 2021). The federal carbon tax rate is expected to rise from $50 per tonne as of April 2022, to $170 per tonne in 2030.
- 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;
- The access to markets for the Company's products; 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

Kelt continues to monitor the impact of the recent Supreme Court of British Columbia judgement (the "Judgment") with respect to a claim brought forth by the Blueberry River First Nation ("Blueberry") against the province of British Columbia regarding the cumulative impact of industrial development within the Blueberry treaty claim area. The Judgement found that the province of British Columbia breached the Treaty 8 rights of the Blueberry by allowing extensive industrial development on the Blueberry's traditional territory without first assessing the cumulative impacts of this development on the ability of the members of the Blueberry to exercise their Treaty 8 rights to hunt, fish, and trap on their traditional territory. Following the judgment, the Government of British Columbia reduced development in the Blueberry treaty claim area resulting in fewer new drilling development permits being issued since July 2021.

On January 18, 2023 the Government of British Columbia and the Blueberry announced an agreement which provides a partnership pathway approach to land, water and resource management in the Blueberry traditional territory. The agreement will include new areas which are protected from industrial development (including oil and gas development) and includes new constraints on developments in other areas while a long-term cumulative effects management regime is implemented.

On January 20, 2023 the Government of British Columbia and four of the Treaty 8 First Nations (Fort Nelson, Saulteau, Halfway River and Doig River First Nations) announced that a consensus was obtained on a collaborative approach to land and resource planning within the traditional territories of the four Treaty 8 First Nations. The initiatives set out in the consensus document include new land-use plans and protection measures, additional measures for shared decision making and a new revenue sharing approach.

The Company does not currently expect that there will be a significant impact to Kelt's 2023 guidance as a result of the new agreements between the Blueberry, the four Treaty 8 First Nations and the Government of British Columbia. Kelt has received drilling development permits in recent months, however Kelt awaits additional information on these agreements to assess the what the impact will be on additional drilling development permits in 2023, and what the long term impact will be on the overall development of oil and gas resources in British Columbia.

Royalty Risks

On October 7, 2021 the Province of British Columbia announced it was launching a comprehensive review of its royalty system. Any future changes to the British Columbia royalty system may have an impact on the Company's future cash flows.

On May 19, 2022 the Province of British Columbia announced a new oil and natural gas royalty framework which includes a capital recovery concept for drill and complete costs and a removal previous incentive programs for deep wells and marginal wells. The new framework will be in place for September 2024. During the transition period new wells will pay 5% royalties for a 12 month period after which royalties will be calculated using the prevailing rates. Existing wells will operate under the existing royalty framework until September 2024. Additional details of the new royalty framework are required for Kelt to quantify the potential impact on future crown royalties.

COVID-19 Related Risks

The COVID-19 pandemic remains a risk and continues to cast some uncertainty on the global economy due to risks surrounding the emergence of new COVID-19 variants and the impact, if any, on commodity prices and equity markets.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, 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.

The Company maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations. Without such insurance, and if the Company becomes subject to environmental liabilities, the payment of such liabilities could be reduce or exceed the funds the Company has available and result in financial distress. 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. Further information is available on the Company's ESG report which can be found on the Company's website.

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.

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.

A more detailed description of the Company's risks is included in the Annual Information Form as at December 31, 2022, dated March 3, 2023 which can be found at www.sedar.com.

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 2023. 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, 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. 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.

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; the cost and timing of future capital expenditures and expected results; the Company's ability to continue accumulating land at a low-cost in its core operating areas and potentially monetize non-core assets; the expected timing of well completions, the expected timing of wells bring brought on-production, the expected timing of facility expenditures, the expected timing of facility start-up dates, the expected timing of production additions from capital expenditures; and the Company's expected future financial position and operating results. 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; and the ability to access sufficient capital. We caution that the foregoing list of risks and uncertainties is not exhaustive.

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 before marketing revenue and P&NG sales after cost of purchases

Throughout this MD&A, reference is made to “P&NG sales”, “P&NG sales before marketing revenue”, and “P&NG sales after cost of purchases”. P&NG sales is as reported in the consolidated financial statements in accordance with GAAP and is before realized gains or losses on financial instruments. P&NG sales before marketing revenue includes P&NG sales (in accordance with GAAP) prior to third party revenue related to the Company's oil blending and third-party natural gas sales. P&NG sales after cost of purchases includes P&NG sales (in accordance with GAAP), net of the cost of third-party volumes purchases. P&NG sales before marketing revenue, and P&NG sales after cost of purchases are used by management to assess the Company's revenue 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 before marketing revenue, and "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 Income in accordance with GAAP. 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. Net realized prices referenced throughout this MD&A are before financial instruments, except as otherwise indicated as being after 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 netback

Operating netback 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 associated financial instruments. The Company also presents operating netbacks on a per BOE basis 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 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)	**2022**	2021	**2022**	2021
Cash used in investing activities	**95,916**	74,421	**328,945**	191,540
Change in non-cash investing working capital	**(27,322)**	(7,303)	**(11,405)**	21,971
Capital expenditures, net of A&D	**68,594**	67,118	**317,540**	213,511
Property acquisitions (1)	**(12)**	(36)	**(933)**	(252)
Property dispositions (1)	**-**	(57)	**41**	9,048
Capital expenditures, before A&D	**68,582**	67,025	**316,648**	222,307

(1) Property acquisitions and property dispositions for the year ended December 31, 2022 includes $2.5 million of non-cash consideration. Property acquisitions and property dispositions for the year ended December 31, 2021 includes $0.2 million of non-cash consideration.

CAPITAL MANAGEMENT MEASURES

Adjusted funds from operations and annualized quarterly adjusted funds from operations

Management considers adjusted funds from operations and annualized quarterly adjusted funds from operations key capital management measures as it demonstrates the Company's ability to meet its financial obligations and cash flow available to fund its capital program. Adjusted funds from operations and annualized quarterly adjusted funds from operations are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Adjusted funds from operations and annualized quarterly adjusted funds from operations is calculated as follows:

	Three months ended December 31		Year ended December 31	
(CA$ thousands, except as otherwise indicated)	**2022**	2021	**2022**	2021
Cash provided by operating activities	**63,742**	52,056	**306,022**	159,714
Change in non-cash working capital	**28,742**	15,058	**17,770**	(1,903)
Funds from operations	**92,484**	67,114	**323,792**	157,811
Settlement of decommissioning obligations	**367**	1,041	**3,200**	3,583
Adjusted funds from operations	**92,851**	68,155	**326,992**	161,394
Annualized quarterly adjusted funds from operations	**371,404**	272,620		

Net debt and net debt to annualized quarterly adjusted funds from operations ratio

Management considers net debt and a net debt to annualized quarterly 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 annualized quarterly 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 annualized quarterly adjusted funds from operations ratio.

SUPPLEMENTARY FINANCIAL 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 GAAP.

P&NG sales, cost of purchases, realized gain (loss) on financial instruments, royalties, revenue after royalties and financial instruments, production expenses, transportation expenses, financing expenses, G&A expenses, realized gain (loss) on financial instruments, gain (loss) on derivative financial instruments, realized loss (gain) on foreign exchange, other income/expense, stock option expense, expiry of mineral leases, depletion and depreciation, impairment (reversal) 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 (loss) and comprehensive income (loss) per share (basic and diluted) is calculated by dividing the amounts by the basic weighted average common shares outstanding.

"Finding, development and acquisition" ("FD&A") cost is the sum of capital expenditures incurred in the period and the change in future development capital ("FDC") required to develop reserves. FD&A cost per BOE is determined by dividing current period net reserve additions into the corresponding period's FD&A cost. Readers are cautioned that the aggregate of capital expenditures incurred in the year, comprised of exploration and development costs and acquisition costs, and the change in estimated FDC generally will not reflect total FD&A costs related to reserves additions in the year.

"Recycle ratio" is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment by comparing the operating netback per BOE to FD&A cost per BOE.

ADDITIONAL INFORMATION

Additional information relating to Kelt, including the Company's Annual Information Form ("AIF") dated March 3, 2023 is filed on SEDAR and can be viewed on their website at www.sedar.com. 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 financial statements of Kelt Exploration Ltd. (the "Company") are the responsibility of management. The financial statements have been prepared by management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") 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 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 financial statements. Their report, contained herein, outlines the nature of their audit and expresses an unqualified opinion on the financial statements.

[signed]

David J. Wilson
President and Chief Executive Officer
March 3, 2023

[signed]

Sadiq H. Lalani
Vice President and Chief Financial Officer
March 3, 2023

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 subsidiaries (together, the Company) as at December 31, 2022 and 2021, 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).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated statement of financial position as at December 31, 2022 and 2021;
- the consolidated statement of net income and comprehensive net income for the years then ended;
- the consolidated statement of changes in shareholders' equity for the years then ended;
- the consolidated statement of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include significant accounting policies 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
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

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, 2022. 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 – Significant accounting policies and note 6 – Property, plant and equipment to the consolidated financial statements.* The Company has $997.2 million of D&P as at December 31, 2022 and depletion and depreciation (D&D) expense was $116.1 million for the year then ended. D&P assets are depleted using the unit-of-production method based on the ratio of production in the year to the related proved reserves, taking into account future development costs necessary to bring those reserves into production. 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. Proved reserves are determined by independent qualified reserve evaluators (management's experts). We determined that this is a key audit matter due to i) the 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	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.

Key audit matter	How our audit addressed the key audit matter
in performing procedures relating to the significant assumptions.	• Recalculated the unit-of-production rates used to calculate D&D expense.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis, which we obtained prior to the date of this auditor's report and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, which is expected to be made available to us after that date.

Our opinion on the consolidated financial statements does not cover the other information and we do not and will not express an opinion or 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 on the other information that we obtained prior to the date of this auditor's report, 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. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

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

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

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

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

The engagement partner on the audit resulting in this independent auditor's report is Scott Don Althen.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 2, 2023

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT DECEMBER 31, 2022 AND DECEMBER 31, 2021

(CA$ thousands)	[Notes]	**December 31, 2022**	December 31, 2021
ASSETS			
Current assets			
Cash and cash equivalents		**125**	719
Accounts receivable and accrued sales	[11]	**81,075**	42,584
Prepaid expenses, deposits and other		**3,599**	2,080
Derivative financial instruments	[11]	**26,751**	5,338
Total current assets		**111,550**	50,721
Derivative financial instruments	[11]	**2,427**	-
Deferred income tax asset	[12]	**-**	10,443
Exploration and evaluation assets	[5]	**16,843**	29,529
Property, plant and equipment	[6]	**997,284**	822,804
Total assets		**1,128,104**	913,497
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities	[11]	**83,288**	72,453
Derivative financial instruments	[11]	**1,414**	1,109
Decommissioning obligations	[8]	**2,187**	2,396
Lease liability	[9]	**505**	609
Total current liabilities		**87,394**	76,567
Bank debt	[7]	**11,300**	1,150
Decommissioning obligations	[8]	**86,445**	112,657
Lease liability	[9]	**543**	399
Deferred income tax liability	[12]	**40,998**	-
Total liabilities		**226,680**	190,773
SHAREHOLDERS' EQUITY			
Shareholders' capital	[10]	**1,162,650**	1,144,596
Contributed surplus and reserve		**(15,460)**	(17,348)
Deficit		**(245,766)**	(404,524)
Total shareholders' equity		**901,424**	722,724
Total liabilities and shareholders' equity		**1,128,104**	913,497
Commitments	[15]		

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]
Neil G. Sinclair, Director

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF NET INCOME AND COMPREHENSIVE NET INCOME
FOR THE YEARS ENDED DECEMBER 31, 2022 AND DECEMBER 31, 2021

		Year ended December 31	
(CA$ thousands, except per share amounts)	[Notes]	**2022**	2021
Revenue			
Petroleum and natural gas sales	[13]	**613,358**	316,763
Royalties		**(65,567)**	(27,414)
		547,791	289,349
Expenses			
Production		**101,566**	69,904
Transportation		**30,467**	25,855
Cost of purchases		**21,438**	6,348
Financing	[14]	**3,911**	2,443
General and administrative	[16]	**10,302**	9,251
Share based compensation	[10]	**7,014**	4,216
Exploration and evaluation	[5]	**14,484**	928
Depletion and depreciation	[6]	**116,183**	91,251
Impairment reversal	[6]	**-**	(70,130)
		305,365	140,066
Loss on derivative financial instruments	[11]	**(32,974)**	(13,656)
Foreign exchange gain		**788**	17
Gain (loss) on sale of assets	[4]	**(196)**	794
Other		**155**	(746)
Net income before taxes		**210,199**	135,692
Deferred income tax expense	[12]	**(51,441)**	(21,436)
Net income and comprehensive income		**158,758**	114,256
Net income per common share			
Basic	[10]	**0.83**	0.61
Diluted	[10]	**0.81**	0.60

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

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2022 AND DECEMBER 31, 2021

		Shareholders' capital				
(CA$ thousands)	[Notes]	Number of Shares (000s)	Amount ($ thousands)	Contributed surplus and reserve	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2020		188,580	1,141,517	(19,053)	(518,780)	603,684
Net income and comprehensive income		-	-	-	114,256	114,256
Exercise of stock options	[10]	291	768	(200)	-	568
Vesting of restricted share units	[10]	293	2,311	(2,311)	-	-
Share based compensation	[10]	-	-	4,216	-	4,216
Balance at December 31, 2021		189,164	1,144,596	(17,348)	(404,524)	722,724
Net income and comprehensive income		-	-	-	158,758	158,758
Exercise of stock options	[10]	2,802	17,896	(4,968)	-	12,928
Vesting of restricted share units	[10]	48	158	(158)	-	-
Share based compensation	[10]	-	-	7,014	-	7,014
Balance at December 31, 2022		**192,014**	**1,162,650**	**(15,460)**	**(245,766)**	**901,424**

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

KELT EXPLORATION LTD.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2022 AND DECEMBER 31, 2021

		Year ended December 31	
(CA$ thousands)	[Notes]	**2022**	2021
Operating activities			
Net income and comprehensive income		**158,758**	114,256
Items not affecting cash:			
Accretion	[14]	**2,451**	2,003
Share based compensation	[10]	**7,014**	4,216
Exploration and evaluation	[5]	**14,484**	928
Depletion and depreciation	[6]	**116,183**	91,251
Impairment reversal	[6]	**-**	(70,130)
Unrealized gain on derivative financial instruments	[11]	**(23,535)**	(2,770)
(Gain) loss on sale of assets	[4]	**196**	(794)
Deferred income tax expense	[12]	**51,441**	21,436
Other		**-**	998
Settlement of decommissioning obligations	[8]	**(3,200)**	(3,583)
Change in non-cash operating working capital	[17]	**(17,770)**	1,903
Cash provided by operating activities		**306,022**	159,714
Financing activities			
Increase in bank debt	[7]	**10,150**	1,150
Proceeds on exercise of stock options	[10]	**12,928**	568
Repayment of lease liability principle	[9]	**(749)**	(745)
Cash provided by financing activities		**22,329**	973
Investing activities			
Exploration and evaluation assets	[5]	**(7,061)**	(4,202)
Property, plant and equipment	[6]	**(309,587)**	(218,105)
Property acquisitions	[4]	**(933)**	(52)
Property dispositions	[4]	**41**	8,848
Change in non-cash investing working capital	[17]	**(11,405)**	21,971
Cash used in investing activities		**(328,945)**	(191,540)
Impact of foreign currency on cash balances		**-**	2
Net change in cash and cash equivalents		**(594)**	(30,851)
Cash and cash equivalents, beginning of year		**719**	31,570
Cash and cash equivalents, end of year		**125**	719

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, primarily 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 annual financial statements on March 2, 2023 for issue on March 3, 2023.

a) Statement of compliance

The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles (“GAAP”) as set out in the *CPA Canada Handbook - Accounting*. These consolidated annual financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”), applicable to the preparation of annual financial statements.

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 11 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, in accordance with the Canadian Oil and Gas Evaluation Handbook (“COGEH”).

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 Company’s 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 estimated proved reserves, which are used, in part, to determine a project's technical feasibility and commercial viability and could be impacted by a shift in demand as global energy markets transition to a lower carbon-based economy. Refer to additional information regarding E&E assets in note 5 of these financial statements.

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, 2022, 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. Refer to specific information regarding the Company's CGUs in note 6 of these financial statements.

Impairment of non-financial assets

Significant judgment is required to assess the Company's non-financial assets, namely E&E and PP&E, for impairment or potential reversals of previously recorded impairment. 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. In addition, judgment is required to assess whether a previously recognized impairment for an asset no longer exists or has decreased.

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.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require significant judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill in the acquisition equation. Future profit (loss) can be affected as a result of changes in future depletion and depreciation or impairment.

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 can fluctuate 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 8 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, the expected timing of settlement is estimated to be between six and ten years, unless the timing to abandon and reclaim a specific well site or facility is known based on budgeted expenditures.

Deferred income taxes

The Company follows the liability method 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. The provision for deferred income taxes also includes the following significant judgments of management:

Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings, and are reduced to the extent it is no longer probable that the related tax benefit will be realized. The Company's non-capital losses expire in years 2033 to 2041.

Share based compensation

The Company uses the fair value method of accounting for its long-term incentive plans, which include an Incentive Stock Option Plan and a Restricted 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 Company uses the Black-Scholes option pricing model 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.

The fair value of restricted share units is estimated based on the volume weighted average trading price ("VWAP") on the TSX over three trading days immediately prior to the date of grant. Judgment is also required to estimate the rate of forfeiture, or number of restricted share units that will ultimately vest. These assumptions are disclosed in note 10 of these financial statements.

Leases

The Company applies judgement in reviewing each of its contractual arrangements to determine whether the lease falls within the scope of IFRS 16. In determining the lease term to be recognized, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option.

The measurement of right-of-use ("ROU") assets and lease liabilities are subject to management's judgement of the applicable incremental borrowing rate when the rate implicit in a lease is not readily determinable. Applicable incremental borrowing rates are based on management's judgements of the economic environment, term, the underlying risk inherent to the asset (which may vary due to changes in the market conditions) and the expected lease term.

Derivative financial instruments

The Company applies judgement in assessing and determining when an embedded derivative exists within a host contract, if the embedded derivative is closely related to the host contract, and the inputs used to fair value an embedded derivative if it is not closely related to the host contract, which would include forecasted benchmark commodity prices.

3. SIGNIFICANT ACCOUNTING POLICIES

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.

Business combinations

Business combinations are accounted for using the acquisition method. The identifiable net assets acquired are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the Consolidated Statement of Net Income and Comprehensive Net Income. Transaction costs associated with the acquisition are expensed when incurred.

Principles of consolidation

As at December 31, 2022, the Company has one wholly-owned subsidiary, Kelt LNG. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as 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 the Company has transferred substantially all risks and rewards of ownership.

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, the Company classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i) Financial assets and liabilities at fair value through profit or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short-term.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the Consolidated Statement of Net Income and Comprehensive Net Income. Gains and losses arising from changes in fair value are presented in profit or loss in the period in which they arise.

Financial assets and liabilities at fair value through profit or loss are classified as current in the Consolidated Statement of Financial Position, except for any portion expected to be realized or paid beyond twelve months of the Consolidated Statement of Financial Position date.

ii) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Company's loans and receivables are comprised of cash and cash equivalents, accounts receivable and deposits. They are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii) Financial liabilities at amortized cost

Financial liabilities at amortized cost include accounts payable and bank debt. Accounts payable are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Bank debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method. Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

iv) Derivative financial instruments

The Company may use derivative financial instruments for risk management purposes. All derivatives have been classified at fair value through profit or loss. 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.

The Company enters into physical commodity contracts, that are entered into and are held for the purpose of receipt or delivery of non-financial items, in accordance with the Company's expected sale requirements. As such, 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 the Company determines that an embedded derivative exists within the contract that needs to be separated out from its host contract. Realized gains or losses from physically settled commodities sales contracts are recognized in petroleum and natural gas sales as the contracts are settled. Embedded derivatives that are separated out from its host contracts are included in profit or loss in the period in which they arise.

Investments in securities

Investments in securities are classified as fair value through profit or loss. Investments in the securities of private entities are carried at fair value, which is estimated using values based on equity issuances and other indications of value (Level 3 fair value hierarchy estimates).

Exploration and evaluation assets and property, plant and equipment

i) Recognition and measurement

Pre-license costs

Costs incurred prior to acquiring the legal rights to explore an area are charged directly to profit or loss as exploration expense in the period incurred. The Company did not incur pre-license costs in the current or prior period.

Exploration and evaluation assets

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 the completion of 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 charged 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. In addition, borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use.

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 divestitures of property, plant and equipment is recognized in the Consolidated Statement of Net Income and Comprehensive Net Income. In addition, risk-sharing 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 Company reviews the carrying value of its non-financial assets, including PP&E and E&E, 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. The Company calculates FVLCD 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.

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

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 Company applies the simplified approach to providing for ECLs, as prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Company uses a combination of historical and forward looking information 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.

Leases

The Company recognizes a ROU asset and corresponding liability on the balance sheet at the date when the leased asset is available for use. Interest expense on the lease liability is recognized over the lease term with an increase to the underlying lease liability. The ROU asset is depreciated over the shorter of the asset's useful life and lease term using the straight line method of depreciation.

ROU assets and lease liabilities are initially measured on a present value basis. Lease liabilities are measured as the net present value of lease payments, less any lease incentives. ROU assets are measured at cost comprising of the initial measurement of the lease liability, any lease payments made at, or before, the commencement date and any initial direct costs and asset restoration costs. The lease liability is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily determinable.

The Company uses a single discount rate for a portfolio of leases with similar characteristics. Leases with lease terms under 12 months and leases where the underlying asset is of low value are not recognized on the balance sheet and are accounted as an expense as incurred.

Provisions and contingencies

Provisions are recognized when the Company has 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 disturbance 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 estimated of the 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 (Loss) and Comprehensive Net Income (Loss) 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 Company follows the liability method of accounting for income taxes. Under this method, deferred income tax is recognized for of 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. 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 offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity or on different tax entities but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously. 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 the Company has with its customers.

The Company applies a practical expedient and does not disclose quantitative or qualitative information on remaining performance obligations that have an original duration of one year or less. Kelt also applies a practical expedient that allows any incremental costs of obtaining contracts with customer to be recognized as an expense when incurred rather than being capitalized.

Kelt evaluates its arrangements 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 Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If management determines that the Company 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.

Financing expense

Financing expenses include interest expense on borrowings and accretion of the discount on decommissioning obligations due to the passage of time.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time required to complete and prepare the assets for their intended use. All other borrowing costs are recognized in financing expense using the effective interest method.

Share based compensation

The Company has an Incentive Stock Option Plan and Restricted Share Unit Plan (collectively, the “Plans”). Pursuant to the Plans, stock options and restricted share units (“RSUs”) may be granted to officers, directors, employees and certain consultants, which call for settlement through the issuance of new common shares of the Company.

The Company applies the fair value method of 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 volume weighted average trading price over three trading days immediately prior to the date of grant. The total fair value associated the stock options and RSUs 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 by the Company on the exercise of stock options is recorded as an increase in shareholders’ capital, together with the corresponding amounts previously recognized in contributed surplus.

Per share amounts

Basic net income per common share is calculated by dividing net income (loss) for the period attributable to common shareholders of the Company 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.

Government grants

Government grants are recognized when there is a reasonable expectation that the conditions attached to the grants have been met, and that the grants will be received. Government grants primarily related to asset expenditures will be presented as a reduction to the capital cost of the asset. Government grants primarily related to income will be presented in the Consolidated Statement of Net Income or Loss as a reduction to the expense line item the grant relates to, in the period in which the expenditures are incurred, or the related income is earned. Government grants primarily related to decommissioning obligations will be presented as a reduction to the carrying value of the obligation once the grant is received.

4. PROPERTY ACQUISITIONS AND DISPOSITIONS

The following table summarizes the fair value of net assets acquired pursuant to property acquisitions during the year ended December 31, 2022 and the prior year ended December 31, 2021:

Acquisitions	**December 31, 2022**	December 31, 2021
Exploration and evaluation assets	**2,479**	242
Property, plant and equipment	**2,273**	96
Decommissioning obligations	**(1,290)**	(86)
Total assets (liabilities) acquired	**3,462**	252
Consideration		
Cash consideration	**(933)**	(52)
Non-cash consideration	**(2,529)**	(200)
Total consideration	**(3,462)**	(252)

Dispositions	**December 31, 2022**	December 31, 2021
Exploration and evaluation assets	**(2,513)**	(1,427)
Property, plant and equipment	**(331)**	(10,808)
Decommissioning obligations	**78**	3,981
Carrying value of net (assets) liabilities disposed	**(2,766)**	(8,254)
Consideration		
Cash consideration, after closing adjustments (1)	**41**	8,848
Non-cash consideration	**2,529**	200
Total consideration	**2,570**	9,048
Gain (loss) on sale of assets	**(196)**	794

(1) The amounts reported in the table above were estimated based on information available at the time of preparation of these financial statements. In particular, closing adjustments were estimated based on interim statements of adjustments. The net gain or loss ultimately recognized by the Company upon determination of final closing adjustments may differ from these estimates.

In the third quarter of 2022, the Company closed a non-cash swap transaction for exploration and evaluation assets with a cost basis of $2.5 million and disposed and acquired some additional non-core assets.

In the third quarter of 2021, the Company disposed of non-core assets for net proceeds of $8.9 million after closing adjustments. The non-core assets had a net carrying value of $8.7 million (property plant and equipment costs of $21.7 million, accumulated depletion and depreciation of $10.9 million, exploration and evaluation costs of $1.4 million and abandonment obligations of $3.5 million), resulting in a gain on sale of $0.2 million.

5. EXPLORATION AND EVALUATION ASSETS

The following table reconciles movements of exploration and evaluation assets:

	December 31, 2022	December 31, 2021
Balance, beginning of year	**29,529**	53,449
Additions	**7,061**	4,202
Property acquisitions [note 4]	**2,479**	242
Property dispositions [note 4]	**(2,513)**	(1,427)
Transfers to property, plant and equipment	**(5,229)**	(26,009)
Exploration and evaluation expense	**(14,484)**	(928)
Balance, end of year	**16,843**	29,529

During the fourth quarter of 2022, the Company expensed approximately $14.2 million of exploratory drilling costs for two exploration wells.

The Company concluded that there are no indicators of potential impairment of its E&E assets at December 31, 2022.

6. PROPERTY, PLANT AND EQUIPMENT

Net carrying value	**December 31, 2022**	December 31, 2021
Development and production assets	**995,464**	821,017
Right-of-use assets	**1,189**	1,009
Corporate assets	**631**	778
Total net carrying value of property, plant and equipment	**997,284**	822,804

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, 2020	1,251,898	5,238	2,503	1,259,639
Additions	217,018	1,087	289	218,394
Property acquisitions [note 4]	96	-	-	96
Property dispositions [note 4]	(21,692)	-	-	(21,692)
Provision	(1,000)	-	-	(1,000)
Change in decommissioning obligations	3,468	-	-	3,468
Transfers from E&E	26,009	-	-	26,009
Balance at December 31, 2021	**1,475,797**	**6,325**	**2,792**	**1,484,914**
Additions	**308,759**	**828**	**789**	**310,376**
Property acquisitions [note 4]	**2,273**	**-**	**-**	**2,273**
Property dispositions [note 4]	**(331)**	**-**	**-**	**(331)**
Change in decommissioning obligations	**(26,884)**	**-**	**-**	**(26,884)**
Transfers from E&E	**5,229**	**-**	**-**	**5,229**
Balance at December 31, 2022	**1,764,843**	**7,153**	**3,581**	**1,775,577**

Accumulated depletion, depreciation and impairment	D&P Assets	Corporate Assets	ROU Assets	Total PP&E
Balance at December 31, 2020	645,566	5,047	1,260	651,873
Depletion and depreciation expense	90,228	500	523	91,251
Impairment reversal	(70,130)	-	-	(70,130)
Dispositions [note 4]	(10,884)	-	-	(10,884)
Balance at December 31, 2021	**654,780**	**5,547**	**1,783**	**662,110**
Depletion and depreciation expense	**114,599**	**975**	**609**	**116,183**
Balance at December 31, 2022	**769,379**	**6,522**	**2,392**	**778,293**

Future development capital expenditures required to develop proved reserves in the amount of $1,210.1 million (December 31, 2021 – $754.6 million) are included in the depletion calculation for development and production assets.

Based on its assessment as of December 31, 2022, the Company determined that there were no indicators of impairment for the Alberta CGU and BC CGU and there are no previous impairments available for reversals.

7. BANK DEBT

The Company has a $100.0 million demand and revolving term facility (“the Credit Facility”) with a syndicate of financial institutions. As at December 31, 2022, $11.3 million was drawn under the Credit Facility, with outstanding letters of credit of $2.0 million. 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 575 basis points depending upon the Company’s Net Debt to Cash Flow ratio of between less than 0.5 times to greater than five times. Under the Credit Facility, borrowings by bankers’ acceptances are also available. Stamping fees fluctuate based on a pricing grid and range from 2.75% to 6.75%, depending upon the Company’s Net Debt to Cash Flow ratio of between less than 0.5 times to greater than five times.

8. 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, 2022	December 31, 2021
Balance, beginning of year	**115,053**	117,060
Obligations incurred	**2,708**	2,395
Obligations acquired	**1,290**	86
Obligations disposed	**(78)**	(3,981)
Obligations settled	**(3,200)**	(3,583)
Changes in discount rate	**(42,428)**	(26,279)
Changes in inflation rate	**8,724**	16,569
Revisions to estimates [(1)]	**4,112**	10,783
Accretion expense	**2,451**	2,003
Balance, end of year	**88,632**	115,053
Decommissioning obligations – current	**2,187**	2,396
Decommissioning obligations – non-current	**86,445**	112,657
Key assumptions		
Risk free rate	**3.3%**	1.7%
Inflation rate	**2.0%**	1.7%

(1) Relates to changes in cost estimates of future obligations, changes in anticipated settlement dates, and an increase of 10% in 2022 to the underlying cost estimates.

The underlying cost estimates are derived from a combination of published industry benchmarks as well as site specific information. As at December 31, 2022 the undiscounted amount of the estimated cash flows required to settle the obligation is $126.4 million (December 31, 2021 – $115.1 million) and is expected to be incurred over the next 50 years. Based on an inflation rate of 2.0%, the undiscounted amount of the estimated future cash flows required to settle the obligation is $247.0 million at December 31, 2022 (December 31, 2021 – $191.6 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 Statement of Net Income and Comprehensive Net Income (note 14).

9. LEASE LIABILITY

	December 31, 2022	December 31, 2021
Balance, beginning of year	**1,008**	1,464
Additions	**789**	289
Interest expense	**46**	67
Lease payments	**(795)**	(812)
Balance, end of year	**1,048**	1,008
Lease liability – current	**505**	609
Lease liability – non-current	**543**	399

The Company has lease liabilities for commercial office space and vehicle leases. The weighted average discount rate for new leases entered in the period ended December 31, 2022 was 9.0% (December 31, 2021 – 5.9%). Payments under the Company's short-term leases were $9.4 million for the year ended December 31, 2022 (December 31, 2021 – $5.0 million), which primarily related to short term drilling rig rentals.

10. 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, 2022 (December 31, 2021 – nil).

	Number of Shares (000s)	Amount ($ thousands)
Balance at December 31, 2020	188,580	1,141,517
Issued on exercise of stock options	291	568
Transfer from contributed surplus on exercise of stock options	-	200
Released upon vesting of restricted share units	293	2,311
Balance at December 31, 2021	**189,164**	**1,144,596**
Issued on exercise of stock options	**2,802**	**12,928**
Transfer from contributed surplus on exercise of stock options	**-**	**4,968**
Released upon vesting of restricted share units	**48**	**158**
Balance at December 31, 2022	**192,014**	**1,162,650**

Stock options

Kelt has an Incentive Stock Option Plan (the "Option Plan") that provides for granting of stock options to directors, officers, employees and certain consultants. The stock options granted pursuant to the Option Plan are to be settled through the issuance of new common shares of the Company which typically 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, 2020	9,967	3.88
Granted	2,642	2.79
Exercised (1)	(291)	1.95
Forfeited	(137)	4.66
Expired	(1,658)	4.72
Balance at December 31, 2021	**10,523**	**3.52**
Granted	**3,528**	**5.40**
Exercised (1)	**(2,802)**	**4.61**
Forfeited	**(333)**	**4.55**
Expired	**(384)**	**6.77**
Balance at December 31, 2022	**10,532**	**3.71**

(1) The average share price on the date stock options were exercised during the year ended December 31, 2022 was $6.94 per common share ($3.87 per common share on average during the year ended December 31, 2021).

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	
	2022	2021
Risk free interest rate	**2.00%**	0.60%
Expected life (years)	**3.5**	3.6
Expected volatility (1)	**76.1%**	79.5%
Expected dividend yield	**0.0%**	0.0%
Expected forfeiture rate	**4.8%**	5.2%
Fair value of options granted during the year ($/share)	**2.87**	1.51

(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, 2022:

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)
$0.00 to $3.50	5,371	2.5	2.14	3,037	2.11
$3.51 to $6.50	4,814	3.2	5.17	1,429	4.76
$6.51 to $9.50	347	0.8	7.76	307	7.88
Total	**10,532**	**2.8**	**3.71**	**4,773**	**3.28**

Restricted share units

Kelt has a restricted share unit plan that provides for granting of restricted share units ("RSUs") to officers, employees and certain consultants. 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, 2020	346
Granted	709
Released upon vesting	(293)
Forfeited	(3)
Balance at December 31, 2021	**759**
Granted	**200**
Released upon vesting	**(48)**
Forfeited	**(38)**
Balance at December 31, 2022	**873**

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

	Year ended December 31	
	2022	2021
Stock options	**5,902**	3,054
Restricted share units	**1,112**	1,162
Total share based compensation expense	**7,014**	4,216

Per share amounts

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)	**2022**	2021
Weighted average common shares outstanding, basic	**191,101**	188,800
Effect of dilution from stock options and RSUs	**4,355**	2,007
Weighted average common shares outstanding, diluted	**195,456**	190,807

The Company uses the treasury stock method to determine the dilutive effect of stock options and RSUs. Under this method, only "in-the-money" dilutive instruments impact the calculation of diluted net income per common share. For the year ended December 31, 2022 and December 31, 2021, the company included the effect of stock options and RSUs in calculating the diluted net income per common share, however, the effect was negligible.

11. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include cash and cash equivalents, investment in securities, accounts receivable and accrued sales, deposits, accounts payable and accrued liabilities, derivative financial instruments, 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 established risk management policies that permit 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, 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 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 at December 31, 2022, the following commodity price risk management contracts are outstanding:

Natural gas derivative contracts

Contract Type [2]	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX fixed price swap	20,000 MMBtu/d	CAD$10.12	Jan 23 – Feb 23
NYMEX fixed price swap	10,000 MMBtu/d	CAD$10.15	Mar 23
AECO 5A fixed price swap	5,000 GJ/d	CAD$4.00/GJ	Apr 23 – Oct 23
NYMEX-AECO 5A basis swap	20,000 MMBtu/d	NYMEX less USD$1.22	Jan 23 – Mar 23
NYMEX-AECO 7A basis swap	10,000 MMBtu/d	NYMEX less USD$0.98	Jan 23 – Mar 23
NYMEX-AECO 5A basis swap	10,000 MMBtu/d	Monthly AECO basis calculated at 30% of the floating monthly NYMEX price	Apr 23 – Oct 24
NYMEX-AECO 5A basis swap	30,000 MMBtu/d	NYMEX less USD$1.10	Nov 24 – Oct 25

Natural Gas Costless Collars [2]	Notional Volume	Floor Price $/MMBtu	Ceiling Price $/MMBTU	Remaining Term
NYMEX costless collar	10,000 MMBtu/d	CAD$9.00	CAD$16.40	Jan 23 – Mar 23
NYMEX costless collar	10,000 MMBtu/d	CAD$9.00	CAD$18.15	Jan 23 – Mar 23
NYMEX costless collar	10,000 MMBtu/d	CAD$9.50	CAD$17.00	Jan 23 – Mar 23

Crude oil derivative contracts

Contract Type [1][3]	Notional Volume	Contract Price $/bbl	Remaining Term
WTI-MSW basis swap	2,500 bbl/d	WTI less USD$2.70	Jan 23 – Jun 23

Crude Oil Costless Collars [1]	Notional Volume	Floor Price $/bbl	Ceiling Price $/bbl	Remaining Term
WTI costless collar	1,000 bbl/d	CAD$100	CAD$130	Jan 23 – Mar 23
WTI costless collar	1,000 bbl/d	CAD$102	CAD$128	Jan 23 – Mar 23

(1) West Texas Intermediate (“WTI”)
(2) NYMEX Henry Hub (“NYMEX”)
(3) Mixed Sweet Blend (“MSW”)

Subsequent to December 31, 2022, the Company unwound its 30,000 MMBtu/d of natural gas costless collar derivative contracts for February and March 2023 for proceeds of $8.06 million and unwound its 20,000 MMBtu/d NYMEX fixed price swaps for February 2023 and 10,000 MMBtu/d NYMEX fixed price swaps for March 2023 for proceeds of $4.65 million.

Natural gas embedded derivative

Contract Type [1]	Notional Volume	Contract Price	Remaining Term
Physical delivery contract	7,458 GJ/d	Floating AESO power pool price (CAD/MWh) divided by the Fixed Heat Rate of 16.95 GJ/MWh	Jan 23 – Mar 23

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

Commencing in November 2022, the Company entered into a five-month natural gas supply agreement to deliver 7,458 GJ/d of gas to the Nova Inventory Transfer point. Under the terms of the agreement, the Company receives a price equal to the Floating AESO Power Pool Price divided by the fixed heat rate of 16.95 GJ/MWh. It was determined that the agreement contained an embedded derivative, with the embedded derivative gains reported under “Loss on derivative financial instruments” in the Consolidated Statement of Net Income and Comprehensive Net Income as of December 31, 2022.

The fair value of the embedded derivative as at December 31, 2022 is calculated by the difference between the forecasted Floating AESO Power Pool Price divided by the fixed heat rate of 16.95 GJ/MWh, less the forecasted AECO 5A price, for the remaining term of the contract.

Subsequent to December 31, 2022, the Company entered into the following commodity price risk management contracts:

Natural gas derivative contracts

Contract Type (1)	Notional Volume	Contract Price $/MMBtu	Remaining Term
NYMEX-AECO 7A basis swap	25,000 MMBtu/d	NYMEX less USD$1.10	Apr 23 – Jul 23
NYMEX-AECO 7A basis swap	35,000 MMBtu/d	NYMEX less USD$1.18	Aug 23 – Oct 23
NYMEX-AECO 5A basis swap	15,000 MMBtu/d	NYMEX less USD$1.17	Apr 23 – Oct 23
NYMEX-AECO 7A basis swap	5,000 MMBtu/d	NYMEX less USD$1.12	Nov 24 – Oct 25

(1) NYMEX Henry Hub (“NYMEX”)

Interest rate risk

The Company is exposed to interest rate risk as changes in market interest rates will impact the Company’s Credit Facility which is subject to a floating interest rate. Based on bank debt balance as of December 31, 2022 of $11.3 million, an increase (decrease) in the market rate of interest by 25 basis points would have an insignificant impact. As at December 31, 2022, 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 at December 31, 2022, the following foreign exchange risk management contracts are outstanding:

Contract Type	Notional Volume	Contract Price	Remaining Term
CAD/USD swap	USD$3.0 million/month	$1.3625 CAD/USD	Jan 23 – Dec 23

Gains and losses on risk management contracts

The table below summarizes realized and unrealized gains (losses) on risk management contracts:

	Year ended December 31	
	2022	2021
Realized loss on financial derivative contracts	**(60,633)**	(16,426)
Realized gain on natural gas embedded derivative	**4,124**	-
Total realized loss on derivative financial instruments	**(56,509)**	(16,426)
Unrealized gain on financial derivative contracts	**15,146**	2,770
Unrealized gain on natural gas embedded derivative	**8,389**	-
Total unrealized gain on derivative financial instruments	**23,535**	2,770
Loss on derivative financial instruments	**(32,974)**	(13,656)

Fair value measurements

The Company classifies fair value measurements using a fair value 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 Company's financial derivative contracts and natural gas embedded derivative are classified as Level 2 and investment in securities are classified as Level 3.

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.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels at December 31, 2022:

	Carrying Value ("CV")			Fair Value		
Balance as at December 31, 2022	Gross	Netting(1)	Net CV	Level 1	Level 2	Level 3
Financial assets						
Derivative financial instrument	20,789	-	20,789	-	20,789	-
Natural gas embedded derivative	8,389	-	8,389	-	8,389	-
Financial liabilities						
Derivative financial instrument	1,414	-	1,414	-	1,414	-

	Carrying Value ("CV")			Fair Value		
Balance as at December 31, 2021	Gross	Netting(1)	Net CV	Level 1	Level 2	Level 3
Financial assets						
Derivative financial instrument	5,338	-	5,338	-	5,338	-
Financial liabilities						
Derivative financial instrument	1,109	-	1,109	-	1,109	-

(1) Financial assets and liabilities are only offset if the Company has the current 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, 2022, the carrying amount of cash and cash equivalents, accounts receivable and accrued sales, and deposits, represent the Company's maximum credit exposure. Cash and cash equivalents are held on deposit with a Canadian chartered bank. The Company's credit risk exposure arises primarily from receivables from oil and gas marketers and joint venture partners.

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

Accounts receivable and accrued sales	**December 31, 2022**	December 31, 2021
Joint venture partners	**11,080**	2,789
Oil and gas marketers	**59,271**	38,534
GST input tax credits	**2,879**	1,740
Risk management contracts	**1,669**	-
Other	**7,160**	138
ECL provision	**(984)**	(617)
Total	**81,075**	42,584

During the year ended December 31, 2022, sales to four oil and gas marketers accounted for approximately 81% of total sales. During the period ended December 31, 2021, sales to five oil and gas marketers accounted for approximately 96% of total sales. Kelt has mitigated some of its credit risk through the majority of its sales to oil and gas marketers which have been rated investment-grade by an independent ratings agency.

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, the Company's production revenues are current. All other accounts receivable are generally contractually due within 30-90 days.

The balance of accounts receivable outstanding for more than 90 days relates primarily to receivables from the Company's 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. As of December 31, 2022, the collection risk on outstanding accounts receivable balances is considered low as less than 1.0% of the accounts receivable balance is outstanding for more than 90 days (December 31, 2021 – 1.0%).

Liquidity risk

The Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's financial liabilities as at December 31, 2022 include accounts payable, derivative financial instruments, lease liabilities and bank debt. The Company manages liquidity risk with its budgeting process which sets out expected debt levels, capital expenditures and funds flow from operations. In addition, risk management contracts such as derivative financial instruments 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, 2022:

	Within 1 Year	1 to 5 Years	More than 5 Years	**Total**
Accounts payable and accrued liabilities	83,288	-	-	**83,288**
Derivative financial instruments	1,414	-	-	**1,414**
Lease liability	505	543	-	**1,048**
Bank debt and estimated interest (1)	746	11,300	-	**12,046**
Total	**85,953**	**11,843**	**-**	**97,796**

(1) Estimated interest for future years related to the Credit Facility was calculated using the weighted average interest rate of 6.6% for the year ended December 31, 2022, 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 and annualized quarterly adjusted funds from operations

Management considers adjusted funds from operations and annualized quarterly adjusted funds from operations key capital management measures that demonstrate the Company's ability to meet its financial obligations and cash flow available to fund its capital program. Adjusted funds from operations and annualized quarterly adjusted funds from operations are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Adjusted funds from operations and annualized quarterly adjusted funds from operations is calculated as follows:

	Three months ended December 31		Year ended December 31	
	2022	2021	**2022**	2021
Cash provided by operating activities	**63,742**	52,056	**306,022**	159,714
Change in non-cash working capital	**28,742**	15,058	**17,770**	(1,903)
Settlement of decommissioning obligations	**367**	1,041	**3,200**	3,583
Adjusted funds from operations	**92,851**	68,155	**326,992**	161,394
Annualized quarterly adjusted funds from operations	**371,404**	272,620		

Net debt and net debt to annualized quarterly adjusted funds from operations ratio

Management considers net debt and a net debt to annualized quarterly 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 Company targets a net debt to annualized quarterly adjusted funds from operations ratio of less than 2.0 times. Net debt and a net debt to annualized quarterly adjusted funds from operations ratio are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities.

Net debt and net debt to annualized quarterly adjusted funds from operations ratio is calculated as follows:

	December 31, 2022	December 31, 2021
Bank debt	**11,300**	1,150
Accounts payable and accrued liabilities	**83,288**	72,453
Cash and cash equivalents	**(125)**	(719)
Accounts receivable and accrued sales	**(81,075)**	(42,584)
Prepaid expenses and deposits	**(3,599)**	(2,080)
Net debt	**9,789**	28,220
Annualized quarterly adjusted funds from operations	**371,404**	272,620
Net debt to annualized quarterly adjusted funds from operations ratio	**0.0**	0.1

As more particularly described in note 7, there are no financial covenants under the Credit Facility agreement and Kelt is in compliance with all other covenants.

12. 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, 2022 are estimated to be approximately $768.4 million (December 31, 2021 – $774.2 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	
	2022	2021
Net income before income taxes	**210,199**	135,692
Canadian statutory tax rate	**23.7%**	23.1%
Expected income tax expense	**49,819**	31,293
Increase (decrease) resulting from:		
Non-deductible expenses (1)	**1,622**	976
Amortization of common control reserve	**-**	(329)
Unrecognized deferred tax assets	**-**	(10,504)
Deferred income tax expense	**51,441**	21,436

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

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 average provincial tax rate in Alberta and British Columbia is 8.0% and 12.0% respectively.

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, 2021	Recognized in profit and CI(1)	Recognized in balance sheet	Balance at December 31, 2022
Derivative financial instruments	(973)	(5,413)	-	(6,386)
PP&E and E&E	(101,641)	(21,097)	-	(122,738)
Decommissioning obligations	26,714	(6,128)	-	20,586
Lease liability	186	8	-	194
Share and debt issue costs	54	(54)	-	-
Reserve from common control transaction	(1)	1	-	-
Non-capital losses (2)	86,104	(18,758)	-	67,346
Net deferred tax asset (liability)	10,443	(51,441)	-	(40,998)

Deferred income tax asset (liability)	Balance at December 31, 2020	Recognized in profit and CI(1)	Recognized in balance sheet	Balance at December 31, 2021
Derivative financial instruments	(336)	(637)	-	(973)
PP&E and E&E	(59,382)	(42,259)	-	(101,641)
Decommissioning obligations	27,177	(463)	-	26,714
Lease liability	286	(100)	-	186
Share and debt issue costs	134	(80)	-	54
Reserve from common control transaction	(330)	329	-	(1)
Non-capital losses (2)	64,330	21,774	-	86,104
Net deferred tax asset (liability)	31,879	(21,436)	-	10,443

(1) Comprehensive income has been abbreviated as "CI".

(2) The Company's non-capital losses expire in years 2033 to 2041.

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

13. 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. Kelt generates marketing revenue from the sales of third party volumes related to the Company's oil blending operations, with the production being sold under the same terms of the Company's variable oil price contracts discussed above.

Where Kelt is the principal to transportation arrangements, gas production sales includes variable priced contracts after the point where title is transferred to a third party. The transaction price for these contracts is based on benchmark commodity prices at a location that is different from the price at which title transfer takes place. For the year end December 31, 2022, transportation costs incurred in relation to these contracts was $12.4 million (December 31, 2021 – $9.9 million).

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

	December 31, 2022	December 31, 2021
Oil production	**240,195**	138,255
Oil treating and other	**718**	722
NGLs production	**99,973**	46,083
Gas production	**249,125**	123,728
Gas processing and other	**1,606**	1,358
Marketing revenue	**21,741**	6,617
Total petroleum and natural gas sales	**613,358**	316,763

Included in accounts receivable at December 31, 2022 is $59.3 million (December 31, 2021 - $38.5 million) of accrued oil and gas sales related to December 2022 production.

14. FINANCING EXPENSES

	Year ended December 31	
	2022	2021
Total interest expense	**1,460**	440
Accretion of decommissioning obligations [note 8]	**2,451**	2,003
Total financing expense	**3,911**	2,443

15. COMMITMENTS

As of December 31, 2022, the Company is committed to future payments under the following agreements:

	2023	2024	2025	2026	2027	Thereafter
Firm processing commitments	18,969	27,700	39,754	39,504	38,812	261,361
Firm transportation commitments	28,887	28,414	26,638	26,997	23,404	48,711
Total annual commitments	**47,856**	**56,114**	**66,392**	**66,501**	**62,216**	**310,072**

In 2022 Kelt entered into two gas processing agreements with third party midstream companies. The gas processing plants are expected to become operational in late 2023 or early 2024 and in the fourth quarter of 2024, with a total expected increase of approximately $300 million to Kelt's future payments under these agreements.

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

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

	Year ended December 31	
	2022	2021
Salaries and benefits [1][2]	**12,287**	9,713
Other G&A expenses	**5,521**	3,745
G&A expenses before recoveries	**17,808**	13,458
Overhead recoveries	**(7,506)**	(4,207)
G&A expense	**10,302**	9,251

(1) Refer to additional information regarding salaries and benefits paid to key management personnel in note 18 of these financial statements.

(2) 2021 salaries and benefits include $0.5 million received as part of the Canada Emergency Wage Subsidy program.

17. SUPPLEMENTAL CASH FLOW INFORMATION

	Year ended December 31	
Changes in non-cash working capital	**2022**	2021
Accounts receivable and accrued sales	**(38,491)**	(21,630)
Prepaid expenses and deposits	**(1,519)**	9,616
Accounts payable and accrued liabilities	**10,835**	35,888
Change in non-cash working capital	**(29,175)**	23,874
Relating to:		
Operating activities	**(17,770)**	1,903
Investing activities	**(11,405)**	21,971
Change in non-cash working capital	**(29,175)**	23,874

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

	Year ended December 31	
Cash outlays in respect of interest and taxes	**2022**	2021
Interest and standby fees on bank debt	**1,068**	116
Taxes [1]	**-**	-

(1) Kelt was not required to pay cash income taxes as the Company had sufficient income tax deductions available to shelter taxable income (note 12).

18. RELATED PARTY TRANSACTIONS

The Company has engaged a law firm where the corporate secretary of Kelt is a partner, and Kelt 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, 2022, the Company incurred $0.4 million (December 31, 2021 – $0.2 million) in disbursements to related parties.

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	
	2022	2021
Salaries, bonuses and other benefits	**2,685**	2,086
Share based compensation	**5,728**	2,959
Total compensation	**8,413**	5,045

During the year ended December 31, 2022, key management personnel were granted 1,636,500 stock options with an exercise price of $5.34 per share and 155,00 RSUs. During the year ended December 31, 2021, key management personnel were granted 1,219,000 stock options with an exercise price of $2.74 per share.

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
MMBtu	million British Thermal Units
GJ	gigajoules
AECO	Alberta Energy Company "C" Meter Station of the NOVA Pipeline System
NIT	NOVA Inventory Transfer ("AB-NIT"), being the reference price at the AECO Hub
WTI	West Texas Intermediate
MSW	Mixed Sweet Blend Edmonton
NYMEX	New York Mercantile Exchange
Station 2	Spectra Energy receipt location
NGX	Natural Gas Exchange Inc. (Canada)
API	American Petroleum Institute
MD&A	Management's Discussion and Analysis
Q1	First quarter ended March 31st
Q2	Second quarter ended June 30th
Q3	Third quarter ended September 30th
Q4	Fourth quarter ended December 31st
YTD	Year to date
BT	Before income taxes
AT	After income taxes
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

Geri L. Greenall [2, 3, 6, 7]
Independent

William C. Guinan [1, 5]
Independent

Michael R. Shea [3, 4, 6]
Independent

Neil G. Sinclair [2, 4, 5, 6]
Independent

Janet E. Vellutini [2, 3, 4]
Independent

David J. Wilson [5]
President & Chief Executive Officer,
Kelt Exploration Ltd..

1 chairman of the board
2 member of the audit committee
3 member of the reserves committee
4 member of the compensation committee
5 member of the health, safety and environment committee
6 member of the nominating committee
7 lead director

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

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