Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of Pieridae Energy Limited ("Pieridae", "we", "our" or the "Company") provides a review by management of the financial performance and position of the Company, as well as the trends and external factors which may impact our prospects. This MD&A has been prepared as of March 20, 2024, and should be read in conjunction with the Company's audited consolidated financial statements and the accompanying notes for the year ended December 31, 2023 and 2022 (the "Consolidated Financial Statements"). The Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Our reporting currency is the Canadian dollar. All amounts are presented in Canadian dollars, unless otherwise stated.

When preparing our MD&A, we consider the materiality of information. Information is considered material if (i) such information results in, or would reasonably be expected to result in, a significant change in the market price or value of our shares; (ii) there is a substantial likelihood that a reasonable investor would consider it important in making an investment decision; or (iii) it would significantly alter the total mix of information available to investors. We evaluate materiality with reference to all relevant circumstances, including potential market sensitivity.

Condensate is a natural gas liquid as defined by National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Throughout this MD&A, natural gas liquids ("NGLs") comprise all NGLs as defined by NI 51-101 other than condensate, which is disclosed separately. Reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 mcf:1 bbl conversion ratio may be misleading as an indication of value.

We are publicly traded on the TSX Exchange under the symbol PEA.TO. Continuous disclosure materials are available on our website, www.pieridaeenergy.com, or on SEDAR, www.sedarplus.com.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures such as net operating income ("NOI"), netback, operating netback, net debt, adjusted operating expense, adjusted working capital and funds flow from operations ("FFO"). Management believes these financial measures are important to the understanding of our business activities. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures we use may not be comparable to similar measures presented by other companies. We use these non-GAAP measures to evaluate our performance. The non-GAAP measures should not be considered an alternative to, or more meaningful than, measures determined in accordance with IFRS, as an indication of our performance. The non-GAAP measures are reconciled to their closest GAAP measure. Refer to "Non-GAAP Measures" section within this MD&A.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

Certain of the statements contained herein including, without limitation, management plans and assessments of future plans and operations, our expected capital budget, our future business plan and strategy, our criteria for evaluating acquisitions and other opportunities, our intentions with respect to future acquisitions and other opportunities, plans and timing for development of undeveloped and probable resources, timing of when we may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, wells to be drilled, the weighting of commodity expenses, expected production and performance of oil and natural gas properties, results and timing of projects, access to adequate pipeline capacity and third-party infrastructure, growth expectations, supply and demand for oil, NGLs, and natural gas, industry conditions, government regulations and regimes, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute "forward-looking statements" or "forward-looking information" within the meaning of Applicable Securities Laws (as defined herein) (collectively "forward-looking statements"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue", "shall", "estimate", "expect", "propose", "might", "project", "predict", "forecast", "target", "goal" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which we operate, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil, natural gas, and NGL prices.

Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of resources estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and resource estimates of our reserves provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements, but which may prove to be incorrect. Although we believe that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because we can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which we operate; the timely receipt of any required regulatory approvals; our ability to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects which we have an interest in, to operate the field in a safe, efficient and effective manner; our ability to obtain financing on acceptable terms; the ability to replace and expand oil and natural gas resources through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and our ability to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we operate; timing and amount of capital expenditures, future sources of funding, production levels, weather conditions, success of exploration and development activities, access to gathering, processing and pipeline systems, advancing technologies, and our ability to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedarplus.com), and at on our website (www.pieridaeenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements contained herein concerning the oil and gas industry and our general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on numerous factors.

DEFINITIONS AND ABBREVIATIONS

Bcf	Billion cubic feet	**MMcf**	Million cubic feet
Bcm	Billion cubic metres	**MMBtu**	Million British thermal units
Mcf	Thousand cubic feet	**Bbl**	Barrel
GJ	Gigajoules	**Boe**	Barrel of oil equivalent
USD	United States Dollars		

PIERIDAE'S OBJECTIVES AND STRATEGY

We are a Canadian energy company headquartered in Calgary, Alberta, and a significant upstream producer and midstream gathering and processing ("G&P") operator with core assets concentrated along the foothills of the Rocky Mountains. Our business is focused on safely producing, processing and delivering to market treated natural gas, condensate, NGLs and sulphur.

We are excited about the opportunities within our asset base and in the regions where we operate. As we continue to mature our deep inventory of conventional drilling prospects, we are focused on diversifying revenue and improving cash flow by increasing third party utilization of our gathering and processing infrastructure, which is strategically located in central and southern Alberta to provide customers competitive processing and egress to natural gas, condensate, NGL, and sulphur markets. We continue to leverage the long-term, low decline characteristics of our reserve base and supporting infrastructure to create long-term shareholder value. The following items are also fundamental to our strategic vision:

- Sustaining a safe and regulatory compliant business.
- Building and continuously improving efficient, cost-effective operations.
- Establishing community and Indigenous partnerships.
- Pursuing opportunities to further integrate environmental, social and governance ("ESG") principles into our business, including implementing a carbon emissions management plan targeting significant emissions intensity reductions.

ANNUAL HIGHLIGHTS

($ 000s unless otherwise noted)	2023	2022	2021
Production			
Natural gas (mcf/d)	168,821	181,677	199,793
Condensate (bbl/d)	2,339	2,860	2,877
NGLs (bbl/d)	2,296	3,729	4,386
Sulphur (tonne/d)	1,306	1,459	1,530
Total production (boe/d) (1)	32,772	36,868	40,562
Reserves			
Net proved plus probable (2P) reserves NPV10 (2)(3)	1,371,735	1,507,413	1,002,134
Financial			
Natural Gas Price ($/mcf)			
Realized before Risk Management Contracts (4)	2.67	5.30	3.60
Realized after Risk Management Contracts (4)	3.67	4.40	2.90
Benchmark natural gas price	2.63	5.36	3.63
Condensate Price ($/bbl)			
Realized before Risk Management Contracts (4)	97.01	114.66	80.24
Realized after Risk Management Contracts (4)	95.55	111.18	63.21
Benchmark condensate price	102.73	121.46	85.95
Net income (loss)	8,981	146,620	(39,790)
Net income (loss) $ per share basic	0.06	0.93	(0.25)
Net income (loss) $ per share diluted	0.04	0.91	(0.25)
Net operating income (5)	130,929	200,989	84,085
Cashflow provided by operating activities	104,202	88,167	51,117
Funds flow from operations (5)	85,692	153,679	20,284
Total assets	638,541	615,477	622,540
Adjusted working capital deficit (6)	(31,830)	(11,249)	(61,588)
Net debt (5)	(204,046)	(214,503)	(293,169)
Capital expenditures (7)	55,539	39,526	34,972

(1) Total production excludes sulphur.
(2) Estimated pre-tax net present value of discounted cash flows from reserves using a 10% discount rate.
(3) The 2021 2P NPV10 reserve value is inclusive of physical hedges. The 2022 and 2023 NPV 10 reserve values does not include physical hedges.
(4) Includes physical commodity and financial risk management contracts inclusive of cash flow hedges, together ("Risk Management Contracts").
(5) Refer to the "Net Operation Income", "Capital Resources" and "non-GAAP measures" sections of this MD&A for reference to non-GAAP measures.
(6) Adjusted working capital is a non-GAAP measure and is calculated as accounts payable and accrued liabilities, less cash and cash equivalents, restricted cash, accounts receivable, prepaids and deposits.
(7) Excludes reclamation and abandonment activities.

QUARTERLY HIGHLIGHTS

The tables below provide a summary of the consolidated financial results for the quarters of 2023 and 2022:

	2023				2022			
($ 000s unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Natural gas (mcf/d)	174,211	155,763	159,427	186,156	179,143	181,030	178,918	187,719
Condensate (bbl/d)	2,384	2,020	2,300	2,657	2,469	2,911	2,864	3,201
NGLs (bbl/d)	1,921	2,273	2,216	2,784	2,389	2,876	3,695	6,003
Sulphur (tonne/d)	1,284	1,124	1,362	1,457	1,348	1,312	1,555	1,625
Total production (boe/d) (1)	33,340	30,253	31,087	36,467	34,715	35,959	36,378	40,491
Financial								
Natural gas price ($/mcf)								
Realized before Risk Management Contracts	2.32	2.65	2.39	3.24	5.08	4.38	7.13	4.66
Realized after Risk Management Contracts	3.12	3.25	3.03	5.12	5.24	3.62	4.67	4.08
Benchmark natural gas price	2.29	2.59	2.40	3.25	5.20	4.28	7.22	4.75
Condensate price ($/bbl)								
Realized before Risk Management Contracts)	97.15	97.47	84.81	107.22	110.24	103.71	132.60	112.09
Realized after Risk Management Contracts)	86.34	80.49	105.84	106.70	117.67	105.82	116.61	106.13
Benchmark condensate price ($/bbl)	104.30	106.30	93.25	107.05	115.24	115.66	132.49	122.62
Net income (loss)	7,414	(16,254)	4,182	13,639	114,662	(1,573)	22,982	10,549
Net income (loss) $ per share, basic	0.05	(0.11)	0.03	0.09	0.72	(0.01)	0.15	0.07
Net income (loss) $ per share, diluted	0.03	(0.11)	0.03	0.08	0.70	(0.01)	0.14	0.07
Net operating income (2)	25,441	11,650	43,843	49,995	67,711	30,014	55,969	47,295
Cashflow provided by operating activities	31,983	7,577	27,533	37,109	40,134	9,899	34,922	3,212
Funds flow from operations (2)	14,269	(1,422)	35,432	37,413	57,641	17,721	43,462	34,855
Total assets	638,541	564,921	575,849	587,641	615,477	473,642	499,580	552,781
Adjusted working capital deficit (3)	(31,830)	(21,454)	(6,258)	(22,275)	(11,249)	(46,419)	(28,892)	(34,934)
Net debt (2)	(204,046)	(205,536)	(181,670)	(202,180)	(214,503)	(254,489)	(248,967)	(273,201)
Capital expenditures (4)	9,306	16,363	9,384	20,486	19,037	7,216	9,739	3,534

(1) Total production excludes sulphur.
(2) Refer to the "Net Operation Income", "Capital Resources" and "non-GAAP measures" sections of this MD&A for reference to non-GAAP measures.
(3) Adjusted working capital is a non-GAAP measure and is calculated as accounts payable and accrued liabilities, less cash and cash equivalents, restricted cash, accounts receivable, prepaids and deposits.
(4) Excludes reclamation and abandonment activities.

2023 OPERATIONAL AND FINANCIAL HIGHLIGHTS

2023 was a significant year for our business. We generated NOI of $130.9 million and FFO of $85.1 million while taking a major step toward increasing financial flexibility, initiated a significant hedge program, and began growing third party processing revenues. Lower natural gas and sulphur prices coupled with unexpected facility downtime and the extended Waterton gas processing facility ("Waterton Facility") turnaround negatively impacted our financial and operating results, however our robust hedge program supported strong cash flows.

The following events impacted our business, operations, cash flows and net income (loss) during the past four quarters:

First quarter of 2023

- Averaged 36,467 boe/d production and realized natural gas price of $5.12/mcf.
- Resolved an unplanned outage at our Caroline gas processing facility ("Caroline Facility" located in the Central Alberta Foothills "CAB") area related to a sulphur condenser vessel repair which began in December 2022.
- Successfully completed drilling our first Brown Creek well (6-35) in Central Alberta in February 2023. The well was put on production in April 2023 and is currently producing approximately 1,980 Mcf/d sales gas at a flowing wellhead pressure of 16 MPa. We chose to defer completion of our second Brown Creek well (6-29) until natural gas prices improve.

Second quarter of 2023

- Averaged 31,087 boe/d production and realized natural gas price of $3.03/mcf.
- Addressed unforeseen facility reliability issues including a second unplanned maintenance outage at our Caroline Facility as well as unplanned downtime at our Jumping Pound gas processing facility ("Jumping Pound Facility"). Production was also impacted by periodic operated and non-operated outages arising from wildfires in Alberta and British Columbia.
- The Caroline Facility outage provided an opportunity to perform some additional maintenance work which allowed us to defer a major turnaround of that facility from 2024 out to 2026.

- Successfully refinanced our previous term loan resulting in a new credit facility totaling USD $150 million which materially reduced our cost of capital and provided greater financial flexibility and liquidity. The previous term loan was retired in advance of its October 2023 maturity. As a result of the refinancing, in 2023 we reduced our total debt by approximately $14 million and doubled our total available liquidity to $45 million.
- Executed an expanded risk management program by entering into several new senior secured financial hedge contracts with terms ranging from 5 to 48 months.

Third quarter of 2023

- Averaged 30,253 boe/d production and realized natural gas price of $3.25/mcf.
- Initiated phase one of the planned major turnaround of our Waterton facility turnaround ("Waterton Turnaround") in August 2023. During the planned turnaround, extensive unplanned repairs were also made to the waste heat boiler; these repairs extended the turnaround operation resulting in ten weeks of facility downtime. Although these repairs decreased production and profitability significantly in the third and fourth quarters, they were necessary to improve the future operational reliability of the Waterton Facility.
- The Board of Directors appointed Darcy Reding as Chief Executive Officer ("CEO") concluding a formal succession process following the retirement of former CEO, Alfred Sorensen. Mr. Reding formerly held the role of President and Chief Operating Officer and was appointed to President, CEO and Director effective September 1, 2023. He has over 30 years of technical and business development experience in both public and private energy companies and will continue to instrumental in achieving our objectives.

Fourth quarter of 2023

- Averaged 33,340 boe/d production and realized natural gas price of $3.12/mcf.
- Successfully completed phase one of the Waterton Turnaround and restarted operations in early November.
- Obtained shareholder approval to enable a conversion feature of the $22 million Bridge Term Loan, inclusive of interest paid in-kind. We intend to repay a portion, or all, of the amounts drawn under the Bridge Term Loan with cash proceeds from non-core divestitures; however, the conversion feature provides optionality should we not complete enough non-core divestitures by the maturity date on December 13, 2024.

We continue to focus on the safety of staff on our sites, executing a wide range of projects without serious injury to personnel. The Total Recordable Injury Frequency ("TRIF") for 2023 is 0.23 as compared to 0.38 in 2022.

2023 GUIDANCE IN REVIEW

Our 2023 guidance evolution was as follows:

	2023 Actual Results	2023 Guidance – August, November 2023		2023 Guidance – March 2023		2023 Guidance – December 2022	
($ 000s unless otherwise noted)		Low	High	Low	High	Low	High
Production (boe/d)	32,772	33,000	34,500	37,000	39,000	37,000	39,000
Net operating income (1)	130,929	110,000	130,000	120,000	150,000	170,000	200,000
Operating netback ($/boe) (1)	10.95	9.00	11.00	9.00	11.00	12.00	14.00
Sustaining capital expenditures (2)	26,776	30,000	40,000	15,000	20,000	50,000	55,000
Development capital expenditures	17,930	15,000	20,000	15,000	20,000	15,000	20,000

(1) Refer to the NOI section of this MD&A for reference to non-GAAP measures.
(2) Comprised of facility maintenance and turnaround capital expenditures.

Guidance in Review

- Released our initial 2023 outlook in December 2022.
- During the year, NOI and Operating Netback guidance was lowered as a result of sustained lower natural gas prices, and lower production.
- Production guidance was revised due to unplanned outages at the Caroline and Jumping Pound Facilities and the extended Waterton Turnaround.

Actual Results

- Ended 2023 slightly below revised production guidance, but exceeded the revised NOI guidance and met the revised Operating Netback guidance due in part to our robust hedge program.
- Met the revised sustaining capital expenditure guidance, which includes the Waterton Turnaround expenditures.
- Met the development capital expenditure guidance, which includes our drilling program concluded in the second quarter.

2024 OUTLOOK

Pieridae's Board of Directors approved 2024 guidance in December 2023. Our near-term priorities are to continue to financially de-leverage while safely sustaining production and implementing cost reduction strategies across our operations and administration. Most importantly, we are focused on attracting new third party volumes to our gathering and processing facilities and maximizing facility reliability.

	2024 Guidance	
($ 000s unless otherwise noted)	**Low**	**High**
Total production (boe/d) (1)	33,000	34,500
Net operating income (2)(3)(5)	80,000	100,000
Operating Netback ($/boe) (3)(4)(5)	6.50	8.00
Capital expenditures	28,000	33,000

(1) 2024 production guidance includes the impact from the Waterton Turnaround phase 2.
(2) Refer to the NOI section of this MD&A for reference to non-GAAP measures.
(3) Refer to Operating Netback section of this MD&A for reference to non-GAAP measures.
(4) Assumes pre-hedge average 2024 AECO price of $2.25/GJ and average 2024 WTI price of USD$70/bbl.
(5) Accounts for impact of hedge contracts in place at December 31, 2023.

Pieridae's specific priorities for 2024 are to:

- Maximize processing facility reliability to meet production targets and maximize third party processing revenue.
- Reduce operating expenses to improve corporate netback.
- Optimize fuel gas consumption to reduce raw gas shrinkage, lower GHG emissions and cost, and increase sales revenue.
- Reduce long term debt to deleverage the balance sheet.

Forward natural gas prices have continued to weaken, particularly over the recent months, as global demand stagnates through a warmer-than-normal winter season resulting in record storage levels and oversupply. Pieridae's robust hedge position will continue to partially mitigate the lower expected natural gas prices through 2024.

Sulphur prices have also fallen year-to-date reflecting weakening global sulphur demand. Pieridae's exposure to the sulphur market is limited for the next 21 months as we sell approximately 80% of our produced sulphur at a fixed price to a third party through the end of 2025.

Approximately 65% of Pieridae's expected 2024 natural gas production is hedged at approximately $3.50/Mcf, and approximately 59% of its expected 2024 condensate production is hedged utilizing swaps and an $80.00 x $90.75 CAD WTI collar. The discounted unrealized gain on the Company's hedge portfolio at December 31, 2023 was approximately $71 million using the December 31, 2023 forward strip.

Pieridae's 2024 capital budget is highlighted by low-cost well and facility optimization projects and the second and final phase of the maintenance turnaround at the Waterton Facility, which is scheduled for the third quarter. The four-week Waterton field production outage associated with this turnaround is reflected in our 2024 production guidance.

The scope and timing of all capital projects continues to be scrutinized in the context of lower year-to-date natural gas prices. Pieridae does not intend to resume its Foothills development drilling program until natural gas prices improve.

While debt reduction remains a top priority for 2024, the ability to repay revolving debt in 2024 may be impacted by low commodity prices and non-discretionary maintenance capital projects. Pieridae expects to draw down the final USD $10 million delayed-draw tranche of the senior secured term loan (the "DDTL") during 2024 to support the final phase of the Waterton Turnaround. The Company's available liquidity also includes USD $12 million remaining undrawn capacity on the senior secured revolving loan as of March 20, 2024.

Pieridae's previously announced Goldboro sale process is ongoing and, if successful, any cash proceeds from the sale will be used to partially repay the company's $22 million convertible Bridge Term Loan which matures on December 13, 2024. The Goldboro process is expected to conclude in the first half of 2024 and, once complete, will mark the conclusion of Pieridae's strategic pivot away from east coast LNG and toward an Alberta-focused natural gas production and processing business.

NET OPERATING INCOME

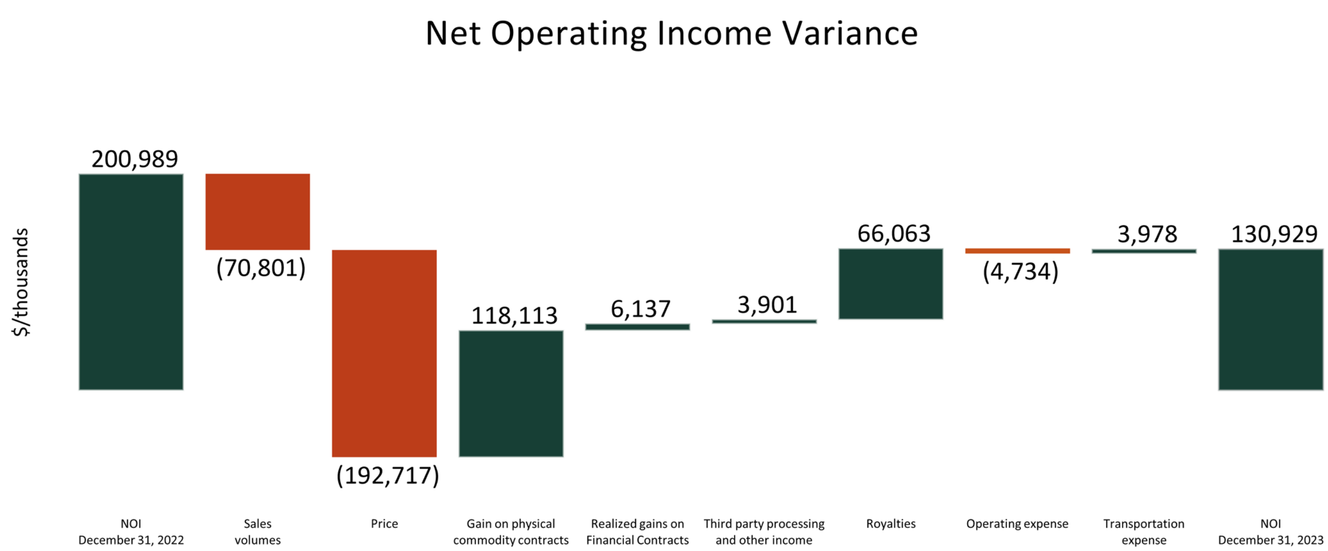
The following table summarizes the Company's net operating income for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Revenue before Risk Management Contracts	67,452	123,581	(45)	287,872	551,390	(48)
Gain (loss) on physical commodity contracts	4,897	4,240	15	54,553	(63,560)	186
Realized gains on Financial Contracts (1)	5,573	-	100	6,137	-	100
Revenue after Risk Management Contracts	77,922	127,821	(39)	348,562	487,830	(29)
Third party processing and other income (2)	12,142	9,534	27	35,086	31,185	13
Revenue	90,064	137,355	(34)	383,648	519,015	(26)
Royalties	(6,315)	(11,926)	(47)	(9,368)	(75,431)	(88)
Operating	(53,399)	(51,879)	3	(224,304)	(219,570)	2
Transportation	(4,909)	(5,839)	(16)	(19,047)	(23,025)	(17)
Net Operating Income (3)	**25,441**	**67,711**	**(62)**	**130,929**	**200,989**	**(35)**

(1) Includes gains or losses on financial risk management contracts and cash flow hedges, together ("Financial Contracts").

(2) Other income includes marketing and transportation and gathering income. In addition to these items, for the year ended December 31, 2023, other income includes a one-time non-refundable deposit paid to Pieridae following an unsuccessful asset disposition, which did not close due to the purchaser's failure to meet closing obligations.

(3) NOI is a non-GAAP measure. Management considers NOI an important measure to evaluate our operational performance as it demonstrates our field level profitability. NOI equals revenue including realized gains (losses) on Financial Contracts, less royalties, operating expenses, and transportation expenses.

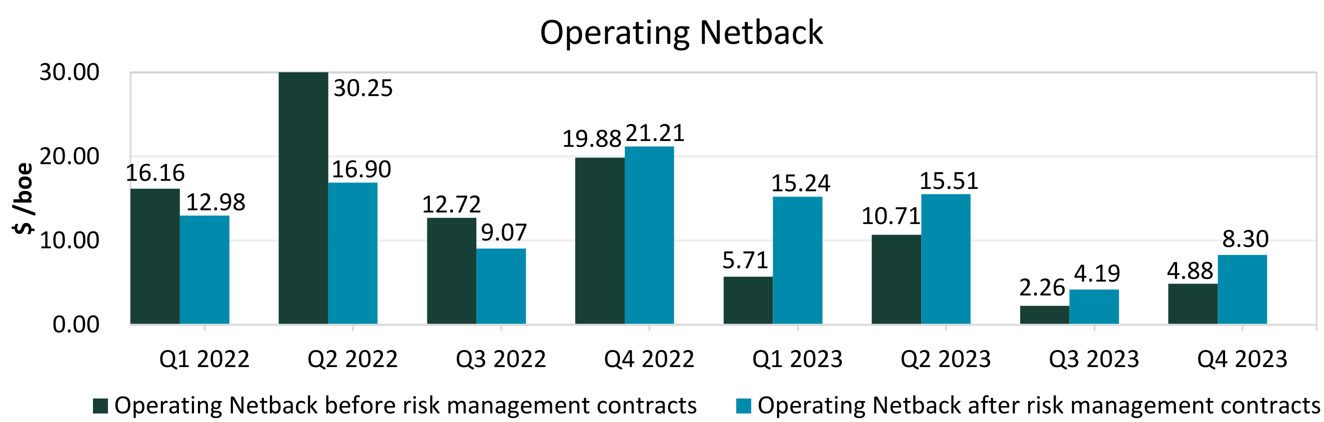


OPERATING NETBACK PER BOE

The following table summarizes the Company's operating netback for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ per boe)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Revenue before Risk Management Contracts	21.99	38.69	(43)	24.07	40.98	(41)
Gain (loss) on physical commodity contracts	1.60	1.33	20	4.56	(4.72)	197
Realized gains on Financial Contracts	1.82	-	100	0.51	-	100
Revenue after Risk Management Contracts	25.41	40.02	(37)	29.14	36.26	(20)
Third party processing and other income	3.96	2.99	32	2.93	2.32	26
Revenue	29.37	43.01	(32)	32.07	38.58	(17)
Royalties	(2.06)	(3.73)	(45)	(0.78)	(5.61)	(86)
Operating	(17.41)	(16.24)	7	(18.75)	(16.32)	15
Transportation	(1.60)	(1.83)	(13)	(1.59)	(1.71)	(7)
Operating Netback ($/boe) (1)	**8.30**	**21.21**	**(61)**	**10.95**	**14.94**	**(27)**

(1) Netback per boe is a "non-GAAP measure". Management considers operating netback an important measure to evaluate the Company's operational performance as it demonstrates Pieridae's field level profitability relative to current commodity prices. Operating netback equals revenue including realized gains (losses) on Financial Contracts, less royalties, operating expenses and transportation expenses calculated on a per BOE basis.

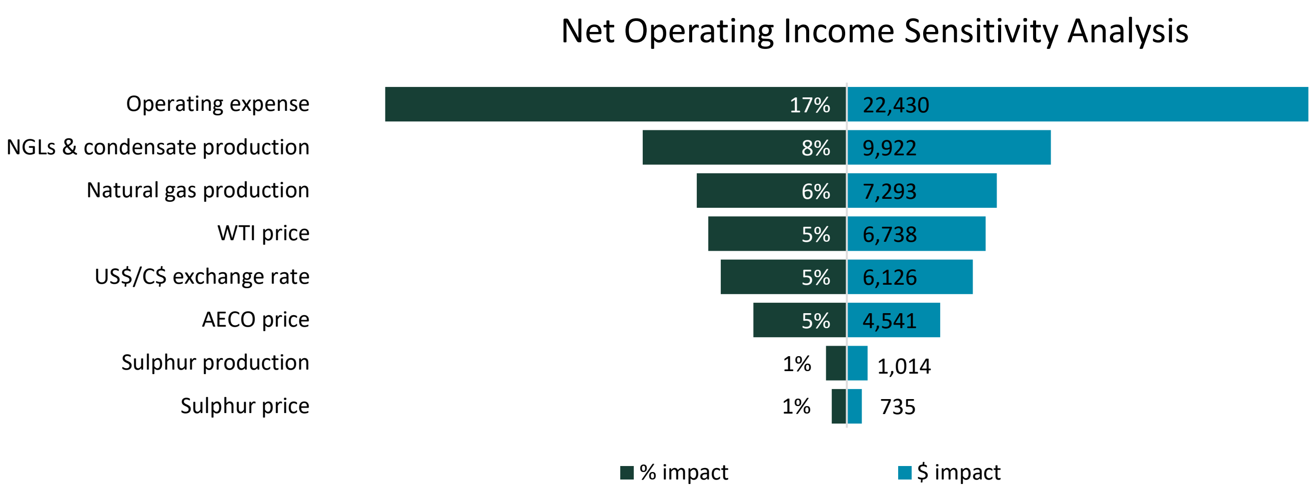


NOI SENSITIVITY ANALYSIS

The following table summarizes the Company's net operating income sensitivity for the three months and year ended December 31, 2023:

	Three months ended December 31				Year ended December 31			
	2023	% Change	$ Impact	% Impact	2023	% Change	$ Impact	% Impact
Business Environment (1) (2)								
WTI price (USD/bbl) (3)	78.52	10%	954	4%	77.64	10%	6,738	5%
AECO price ($/mcf) (4)	2.29	10%	953	4%	2.63	10%	4,541	5%
Sulphur price ($/tonne)	118.29	10%	195	1%	128.60	10%	735	1%
USD/CAD average exchange rate (5)	0.7340	10%	867	3%	0.7409	10%	6,126	5%
Operational (1) (6) (7)								
NGLs & condensate production (bbl/d)	4,305	10%	1,880	7%	4,635	10%	9,922	8%
Natural gas production (mcf/d)	174,211	10%	1,859	7%	168,821	10%	7,293	6%
Sulphur production (tonne/d)	1,284	10%	245	1%	1,306	10%	1,014	1%
Royalty burden	9%	1%	779	3%	3%	1%	3,486	3%
Operating expense ($/boe)	17.41	10%	5,340	21%	18.75	10%	22,430	17%

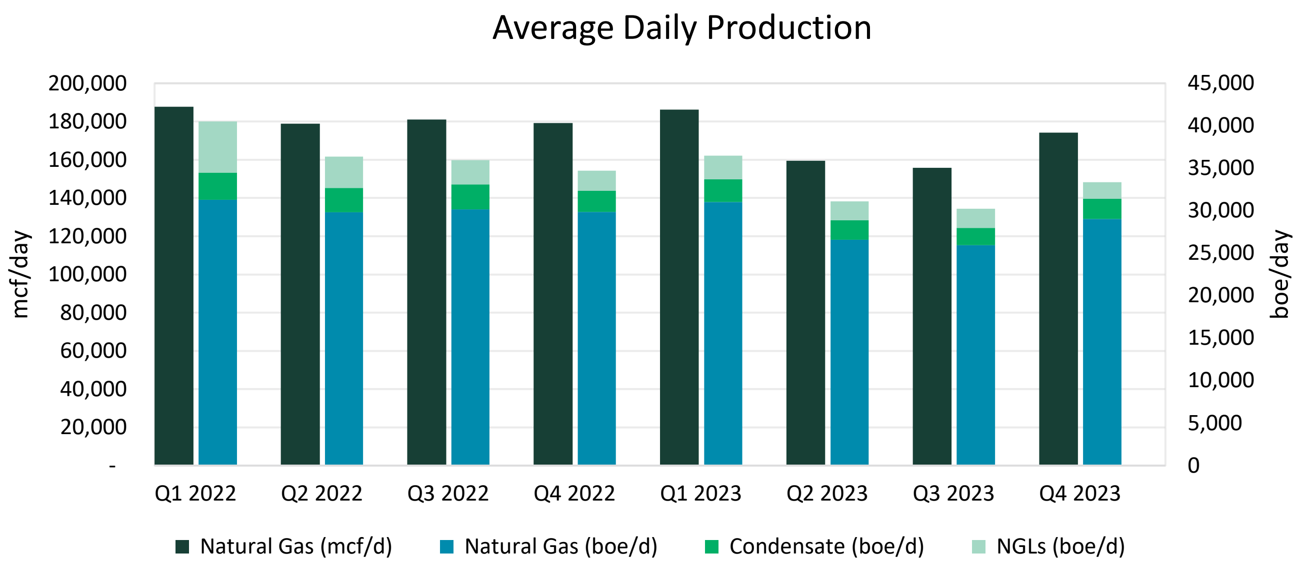
(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change simultaneously.
(2) The indicative impact on NOI would only be applicable within a limited range of these amounts as royalty burden is held constant.
(3) Includes the impact of WTI price on NGL (C3, C4) and condensate (C5) prices assuming a correlation to USD WTI.
(4) Includes the impact of AECO price on NGL (C2) price assuming a correlation to AECO.
(5) Includes the impact of foreign exchange on NGL and Condensate prices assuming a correlation to USD WTI.
(6) Includes the impact of physical commodity hedges that were in place during the period.
(7) Operational assumptions are based upon the results for the three months and year ended December 31, 2022, and the calculated impact NOI would only be applicable within a limited range of these amounts.



PRODUCTION

	Three months ended December 31			Year ended December 31		
	2023	2022	% Change	2023	2022	% Change
Natural gas (mcf/d)	174,211	179,143	(3)	168,821	181,677	(7)
Condensate (bbl/d)	2,384	2,469	(3)	2,339	2,860	(18)
NGLs (bbl/d)	1,921	2,389	(20)	2,296	3,729	(38)
Sulphur (tonne/d) (1)	1,284	1,348	(5)	1,306	1,459	(10)
Total production (boe/d) (1)	**33,340**	**34,715**	**(4)**	**32,772**	**36,868**	**(11)**
Natural gas production (%)	87	86	1	86	82	4
Liquids production (%)	13	14	(1)	14	18	(4)

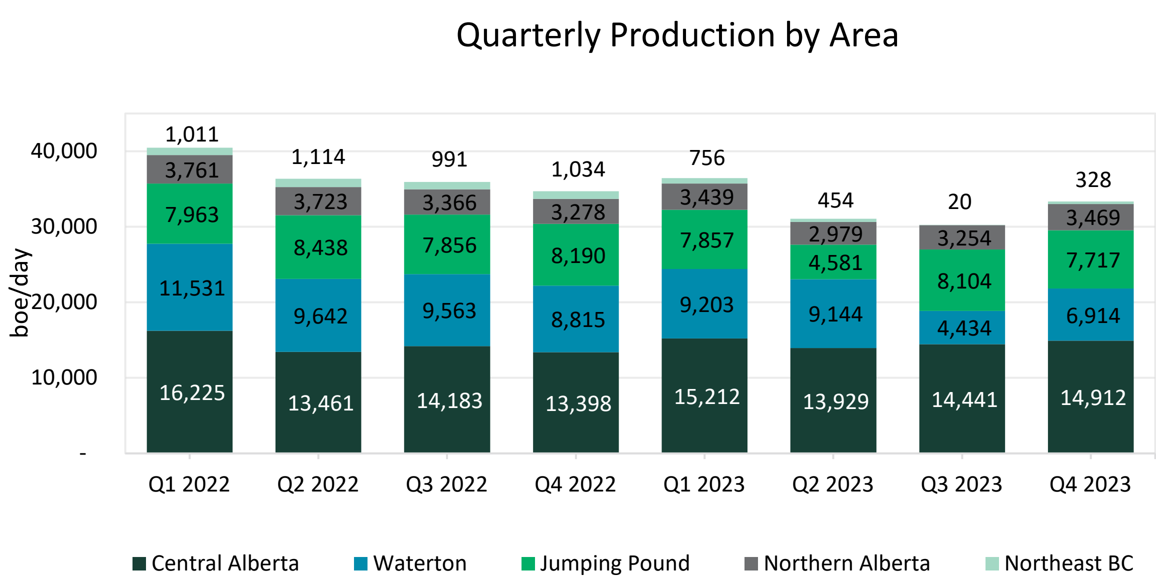
(1) Total production excludes sulphur.



Production By Area

The following table summarizes the Company's production by core area for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
	2023	2022	% Change	2023	2022	% Change
Waterton	6,914	8,815	(22)	7,410	9,880	(25)
Jumping Pound	7,717	8,190	(6)	7,067	8,112	(13)
CAB	14,912	13,398	11	14,623	14,309	2
Northern Alberta Foothills	3,469	3,278	6	3,285	3,530	(7)
Northeast BC	328	1,034	(68)	387	1,037	(63)
Total production (boe/d)	**33,340**	**34,715**	**(4)**	**32,772**	**36,868**	**(11)**



2023 annual and fourth quarter production decreased across all products as compared to the same periods in 2022. The primary driver of the decrease was the planned, but extended, Waterton Turnaround, which impacted production by 1,899 boe/d and 2,878 boe/d respectively for the three months and year ended December 31, 2023 as compared to the same periods in 2022. Waterton is our highest liquids producing area, so the extended turnaround substantially impacted corporate liquids production.

Our 2023 production was also negatively affected by shut-in volumes in various areas for the three months and year ended December 31, 2023, as compared to the same periods in 2022:

- Production in our Clearwater gas field remained shut in during the fourth quarter due to low natural gas prices and a high proportion of variable operating costs; this field will remain shut-in until there is a recovery of gas prices; comparatively, this property produced 782 boe/d and 459 boe/d, respectively.
- Production in our northeast British Columbia ("Northeast BC") area was shut in during Q2 in response to wildfires to ensure the safety of staff and integrity of assets, impacting production by 655 boe/d and 622 boe/d, respectively. This production has now been restored. Certain non-operated areas across central and northern Alberta were also temporarily impacted by wildfire-related shut-ins.
- Unplanned facility downtime at the Jumping Pound Facility during the second quarter, and in the Jumping Pound field during the fourth quarter related to field compressor maintenance (260 boe/d and 667 boe/d, respectively).

RESERVES

Our qualified, independent reserve evaluators, Deloitte, completed the reserve evaluations of our assets effective December 31, 2023 and 2022, which is summarized in the following tables:

	Year ended December 31 MMboe			Year ended December 31 $000, NPV10 (1)		
	2023	**2022**	**% Change**	**2023**	**2022 (3)**	**% Change**
Reserves Category (2)						
Net proved developed producing ("PDP") reserves	**120.7**	126.8	(5)	**614,072**	788,347	(22)
Net proved ("1P") reserves	**191.2**	208.7	(8)	**1,053,896**	1,204,913	(12)
Net proved plus probable ("2P") reserves	**252.5**	289.1	(13)	**1,371,735**	1,507,413	(9)

(1) Estimated pre-tax net present value of discounted cash flows from reserves using a 10% discount rate at evaluator consensus (IC4) price forecast dated January 1, 2024.
(2) Net reserves reflect working interest share of the asset prior to the deduction of royalties.
(3) 2022 comparative values have been restated to remove hedging gains and losses to conform with current year presentation.

Change in Reserve Volumes

Reserve volumes at December 31, 2023 decreased from prior year across PDP, 1P and 2P categories, reflecting 2023 production of approximately 12.0 MMboe. Price forecast changes reduced the economics of producing certain reserves and resulted in decreases of 6.5 MMboe, 6.8 MMboe and 13.9 MMboe in PDP, 1P and 2P reserves, respectively. In addition, PDP reserves increased by 11.9 MMboe due to positive technical revisions related to well performance, cost improvements, lower royalties, and facility optimization. 1P and 2P reserves were impacted by negative technical revisions of 2.0 MMboe and 15.4 MMboe respectively due to the removal of two Proved Undeveloped ("PUD") locations, a reduction in forecast facility throughput, and overall impacts of economic truncation, offset by a land acquisition which added 1.0 net PUD location.

Change in Reserve Value

The 2P reserve value at December 31, 2023 was estimated to be $1,371.7 million on a pre-tax basis using a 10% discount rate, compared to $1,507.4 million in the prior year. The decrease in value was primarily due to the lower commodity price forecast as well as negative technical revisions resulting from earlier economic truncation in certain areas. The total 2P reserve life index was 20.4 years and 19.8 years as of December 31, 2023 and 2022, respectively.

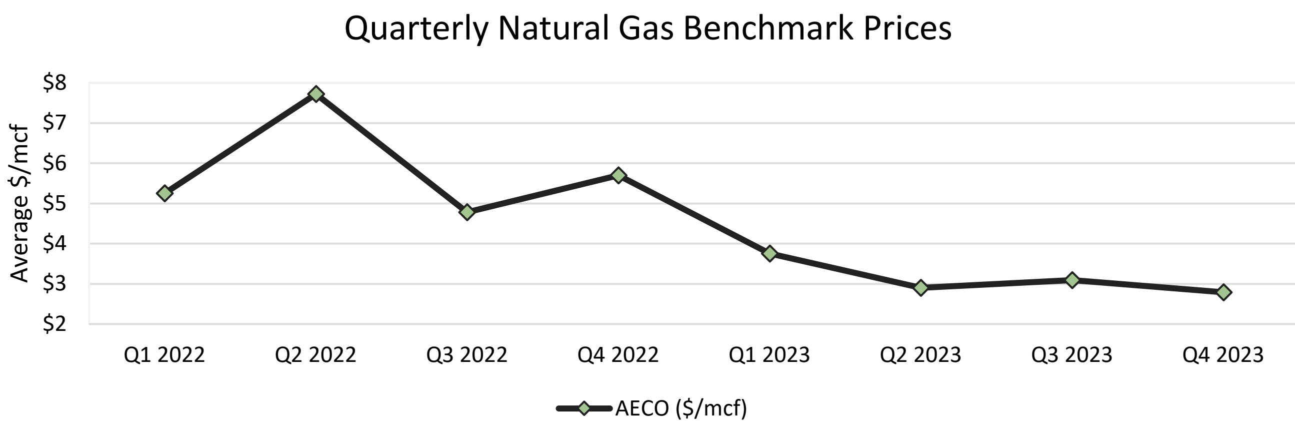
Total undiscounted future development capital ("FDC") included in the reserve estimate was $643.4 million and $791.0 million for 1P and 2P respectively (December 31, 2022 - $807.5 million and $1116.7 million for 1P and 2P respectively). The FDC includes capital for undeveloped drilling locations, facility maintenance, turnarounds, consolidations, and well and facility reactivations.

Refer to the Company's Annual Information Form for the year ended December 31, 2023, for more information about our reserves.

BENCHMARK PRICES

The following table summarizes benchmark commodity pricing for the three months and year ended December 31, 2023 and 2022:

					Year ended December 31		
	Q4 2023	Q4 2022	% Change	Q3 2023	2023	2022	% Change
Natural Gas							
AECO ($/mcf)	2.29	5.20	(56)	2.59	2.63	5.36	(51)
Henry Hub (USD/MMbtu)	2.75	5.54	(50)	2.58	2.53	6.39	(60)
Chicago Citygate (USD/Mmbtu)	2.27	5.35	(58)	2.30	2.31	6.09	(62)
Basis Differential AECO-NYMEX Premium (Discount) (USD/MMbtu)	(1.07)	(1.70)	37	(0.65)	(0.58)	(2.26)	74
Condensate							
C5 at Edmonton ($/bbl)	104.30	115.24	(9)	106.30	102.73	121.46	(15)
Differential C5-WTI Premium (Discount) (USD/bbl)	(1.99)	2.31	(186)	(2.75)	(1.54)	(0.75)	105
West Texas Intermediate crude oil (USD/bbl)	78.52	82.65	(5)	82.10	77.64	94.59	(18)
Sulphur ($/tonne)	118.29	188.95	(37)	107.09	128.60	344.42	(63)
USD/CAD average exchange rate	0.7350	0.7365	-	0.7455	0.7412	0.7865	(6)



We sell natural gas into the TC Energy Nova Gas Transmission Ltd. system and 100% of our natural gas production is priced at AECO. AECO pricing is derived from the Henry Hub and Chicago markets less an AECO basis differential related to the transportation of Canadian gas into the United States ("US") gas transportation system.

US and AECO natural gas pricing decreased for the three months and year ended December 31, 2023 as compared to 2022 by 56% and 51% respectively, and by 12% from the third quarter of 2023. Mild weather during the winter season, full storage, and record levels of production in Canada and the US continued the downward pressure throughout 2023.

We primarily sell produced condensate into the Edmonton market for use as diluent; condensate pricing is highly correlated to the WTI crude oil price as it is primarily used as diluent to reduce the viscosity of heavy oil for transportation through pipelines. Condensate and WTI pricing decreased by 9% and 5% compared to the quarter ended December 31, 2022, and by 15% and 18% compared to the year ended December 31, 2022. The decreases for both benchmarks, as compared to their respective prior periods, were attributable to more than one factor including an increase in global supply and softening demand.

The Company's sulphur production is sold into a variety of markets including directly to North American fertilizer manufacturers as well as international markets through Vancouver or Tampa Bay sulphur export facilities. In 2023, sulphur benchmark prices declined compared to 2022, which was a year of extreme price volatility with prices ranging from $89/tonne to $601/tonne at Vancouver. Sulphur pricing was somewhat less volatile in 2023 with Vancouver benchmark prices ranging from $85/tonne to $224/tonne.

REALIZED PRICES

The following table summarizes the Company's realized pricing for the three months and year ended December 31, 2023 and 2022:

					Year ended December 31		
	Q4 2023	Q4 2022	% Change	Q3 2023	2023	2022	% Change
Realized Natural Gas Price							
Before Risk Management Contracts ($/mcf)	2.32	5.08	(54)	2.65	2.67	5.30	(50)
After Risk Management Contracts ($/mcf)	3.12	5.24	(40)	3.25	3.67	4.40	(17)
Realized Condensate Price							
Before Risk Management Contracts ($/bbl)	97.15	110.24	(12)	97.47	97.01	114.66	(15)
After Risk Management Contracts ($/bbl)	86.34	117.67	(27)	80.49	95.55	111.18	(14)
NGLs ($/bbl)	35.38	47.55	(26)	31.87	36.27	41.36	(12)
Sulphur ($/tonne)	22.54	34.85	(35)	13.34	21.86	44.88	(51)

The following table outlines our volumes sold at spot price versus our volumes sold under Risk Management Contracts:

	Three months ended December 31				Year ended December 31			
	2023		2022		2023		2022	
(% of product volume)	% spot	% hedge	% spot	% hedge	% spot	% hedge	% spot	% hedge
Natural gas	29	71	30	70	34	66	41	59
Condensate	26	74	59	41	48	52	61	39
NGLs	100	-	100	-	100	-	100	-
Sulphur [(1)]	100	-	100	-	100	-	100	-
Total production	32	68	37	63	40	60	48	52

(1) Total production excludes sulphur.

We are contractually obligated to sell the majority of our sulphur production for $6.00/tonne FOB facility gate under a fixed-price physical contract which expires on December 31, 2025. This contract represented 78% of produced sulphur volumes for both the three months and year ended December 31, 2023, respectively (78% and 81% for the three months and year ended December 31, 2022, respectively). If this fixed-priced sulphur sales contract was removed, average realized sulphur prices for the three months and year ended December 31, 2023, would have been $73.47/tonne and $84.09/tonne respectively ($117.88/tonne and $197.41/tonne for the three months and year ended December 31, 2022, respectively).

RISK MANAGEMENT CONTRACTS

Our risk management program is governed by our hedge policy. Our hedge policy is designed to manage risks associated with volatility in natural gas, NGL, and power prices, and fluctuations in foreign exchange rates. Risk management contracts are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. We continuously review the need or requirement to utilize risk management contracts. As at December 31, 2023, our future production is hedged in accordance with the thresholds of our senior loan agreement, which averages approximately 65% of our forecast PDP natural gas and condensate production, net of annualized royalties, from 2024 to mid-2027.

Financial Contracts are considered derivative financial instruments. Their impacts are recorded at their fair value with changes in their fair value and unrealized gains and losses being recognized in net income if hedge accounting is not applied and through other comprehensive income ("OCI") if hedge accounting is applied. Realized gains and losses are recognized in net income. We classify our AECO natural gas swaps and our WTI crude oil collars and swaps as cash flow hedges and apply hedge accounting accordingly. There was no hedge ineffectiveness identified as of December 31, 2023.

Fixed price physical power purchase and commodity sales contracts are recognized in the applicable financial statement line item they are associated with; physical power contracts are recognized in operating expense and physical commodity contracts are recognized in revenue. Physical risk management contracts are not considered to be derivative financial instruments as they are settled based on physical receipt or delivery of the product and therefore are not recorded at fair value.

The following realized gains or losses were generated from our Risk Management Contracts:

	Three months ended December 31			Year ended December 31		
($ 000s)	2023	2022	% Change	2023	2022	% Change
Gain on physical power contracts	**1,279**	12,265	(90)	**30,817**	35,130	(12)
Gain (loss) on physical commodity contracts						
AECO	**4,897**	2,551	91	**53,049**	(59,931)	188
WTI	**-**	1,689	(100)	**1,504**	(3,629)	141
Realized gain (loss) on Financial Contracts						
AECO	**8,001**	-	-	**8,890**	-	-
WTI	**(2,428)**	-	-	**(2,753)**	-	-
Total realized gain (loss) on risk management	**11,749**	16,505	(29)	**91,507**	(28,430)	400

The following unrealized gains or losses were generated from our Financial Contracts:

	Three months ended December 31		Year ended December 31	
($ 000s)	2023	2022	2023	2022
Unrealized gain (loss) on Financial Contracts (1)				
AECO	-	(194)	**194**	(194)
WTI	-	445	**(445)**	445
Unrealized gain (loss) on Financial Contracts, net of tax (2)				
AECO	**50,976**	-	**58,513**	-
WTI	**11,870**	-	**(5,904)**	-
Total unrealized gain Financial Contracts	**62,846**	251	**52,358**	251

(1) Recognized in net income on the Consolidated Financial Statements.
(2) Recognized in OCI on the Consolidated Financial Statements.

Outstanding Commodity Price Contracts

The following fixed price physical commodity sales contracts and power contracts were in place at December 31, 2023:

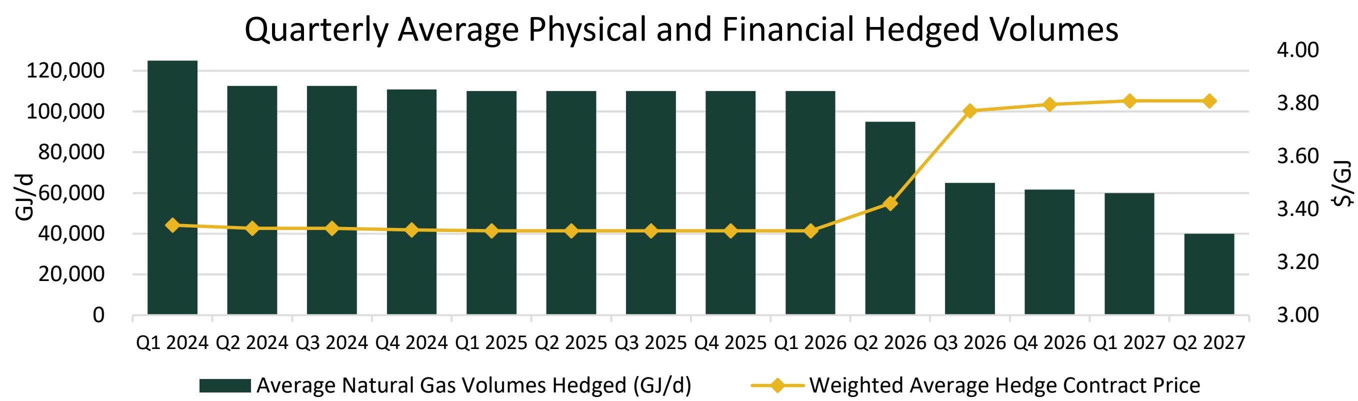
Type of contract	Quantity	Time Period	Average Contract Price
Fixed Price - Natural Gas Sales	20,000 Gj/d	Jan 2024 - Mar 2024	CAD $3.45 /GJ
Fixed Price - Natural Gas Sales	7,500 Gj/d	Apr 2024 - Oct 2024	CAD $3.45 /GJ
Fixed Price - Natural Gas Sales	5,000 Gj/d	Nov 2024 - Oct 2026	CAD $3.31 /GJ
Fixed Price - Power Purchases	55 MW/h	Jan 2024 - Dec 2024	CAD $68.38 /MWh
Fixed Price - Power Purchases	55 MW/h	Jan 2025 - Dec 2025	CAD $79.12 /MWh
Fixed Price - Power Purchases	50 MW/h	Jan 2026 - Dec 2026	CAD $75.88 /MWh
Fixed Price - Power Purchases	25 MW/h	Jan 2027 - Dec 2027	CAD $70.19 /MWh

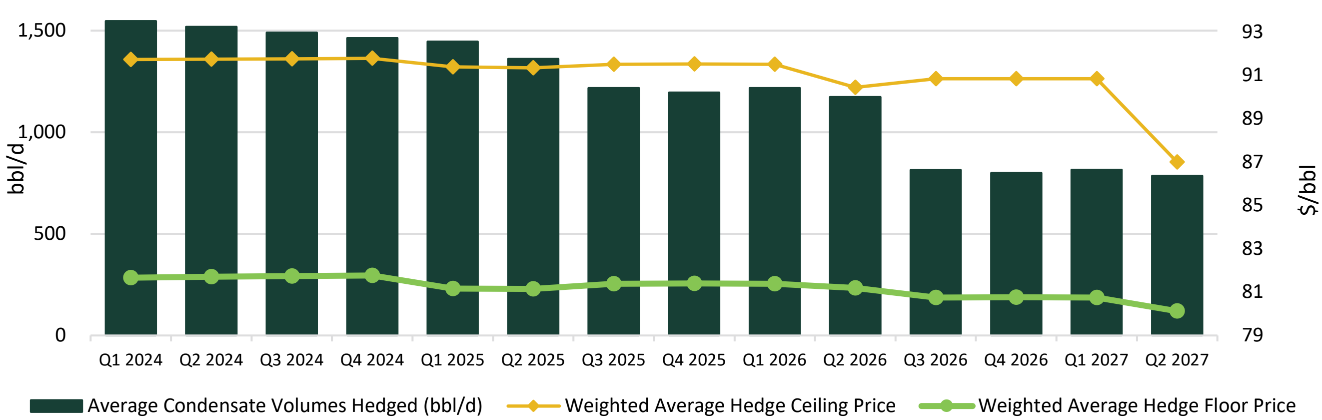
The following Financial Contracts, which hedge accounting is applied, were in place at December 31, 2023:

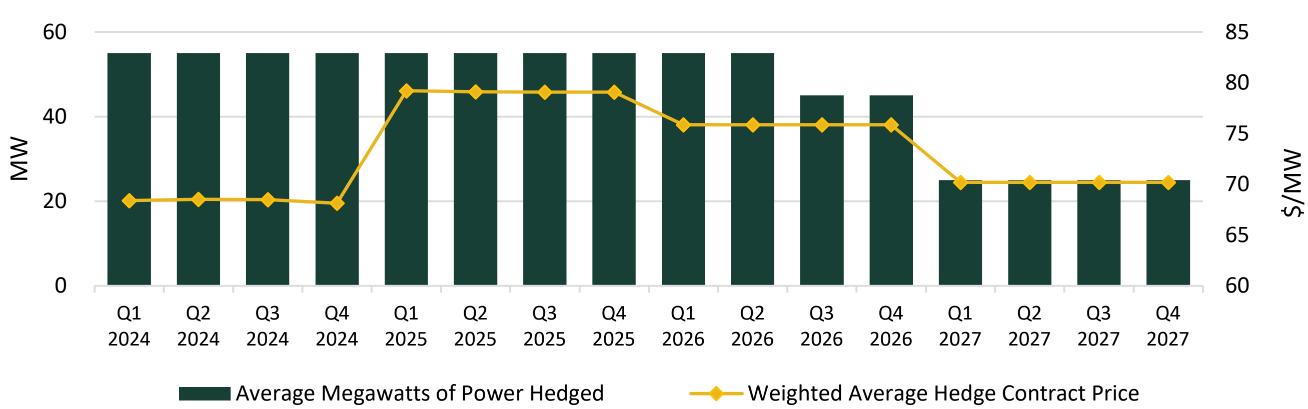
Type of contract	Quantity	Time Period	Contract Price
AECO Natural Gas Swap	30,000 Gj/d	Jan 2024 - May 2026	CAD $3.10 /GJ
AECO Natural Gas Swap	50,000 Gj/d	Jan 2024 - May 2026	CAD $3.30 /GJ
AECO Natural Gas Swap	25,000 Gj/d	Jan 2024 - May 2027	CAD $3.62 /GJ
AECO Natural Gas Swap	35,000 Gj/d	Jun 2026 - May 2027	CAD $3.95 /GJ
WTI Crude Oil Collar	1,401 bbl/d	Jan 2024 - Dec 2024	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	1,235 bbl/d	Jan 2025 - Dec 2025	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	918 bbl/d	Jan 2026 - Dec 2026	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Collar	761 bbl/d	Jan 2027 - May 2027	CAD $80.00 - $90.75 /bbl
WTI Crude Oil Swap	30 bbl/d	Jan 2024 - Dec 2024	CAD $110.25 / bbl
WTI Crude Oil Swap	70 bbl/d	Jan 2024 - May 2026	CAD $104.00 / bbl
WTI Crude Oil Swap	350 bbl/d	Jun 2026	CAD $82.33 / bbl
WTI Crude Oil Swap	50 bbl/d	Jul 2026 - May 2027	CAD $92.25 / bbl
WTI Crude Oil Swap	750 bbl/d	Jun 2027	CAD $78.75 / bbl

The following financial risk management contracts to hedge foreign exchange exposure, upon which hedge accounting is not applied, were in place at December 31, 2023:

Type of contract	Quantity (USD) *($ 000s)*	Time Period	Average Contract Price
USD Call Option	$5,198	Jan 2024 - Mar 2024	CAD $1.3900
USD Call Option	$5,127	Apr 2024 - Jun 2024	CAD $1.3900
USD Call Option	$5,036	Jul 2024 - Sep 2024	CAD $1.3900
USD Call Option	$4,910	Oct 2024 - Dec 2024	CAD $1.3590







PETROLEUM AND NATURAL GAS REVENUE

The following table summarizes the Company's revenue for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Natural gas	42,125	86,323	(51)	217,291	291,602	(25)
Condensate	21,307	26,725	(20)	84,318	116,041	(27)
NGLs	6,254	10,451	(40)	30,399	56,290	(46)
Sulphur	2,663	4,322	(38)	10,417	23,897	(56)
Petroleum and natural gas revenue (1)	**72,349**	**127,821**	**(43)**	**342,425**	**487,830**	**(30)**
Petroleum and natural gas revenue ($/boe)	23.59	40.02	(41)	28.63	36.25	(21)
Third party processing and other income (2)	12,142	9,534	27	35,086	31,185	13
Realized gain (loss) on Financial Contracts	5,573	-	-	6,137	-	-
Total revenue	**90,064**	**137,355**	**(34)**	**383,648**	**519,015**	**(26)**

(1) Petroleum and natural gas revenue includes gains and losses on physical commodity contracts.

(2) Other income includes marketing and transportation and gathering income. In addition to these items, for the year ended December 31, 2023, other income includes a one-time non-refundable deposit paid to Pieridae for a disposition that failed to close.

Revenue is derived from the sale of natural gas, condensate, NGLs, sulphur, and fees earned by processing and handling third party production. Fluctuations in revenue occur due to commodity price volatility which is mitigated through our hedge policy. Petroleum and natural gas revenue decreased for the three months and year ended December 31, 2023 compared to the same periods of 2022, attributable to both decreased production and lower commodity prices.

Third party processing and other income is primarily derived from fees charged to third parties for processing and handling their produced volumes through our gas processing facilities. For the year ended December 31, 2023, third party volumes processed at the Caroline Facility increased by 5,350 MMcf/d or 24%, which increased revenue by $1.5 million. However, various previously discussed facility outages during the year diminished our ability to process third party volumes, decreasing revenue by $2.5 million. Finally, reduced trucked-in sulphur volumes into the Shantz sulphur handling facility resulted in decreased third-party revenue of $1.0 million.

Other income was favorably impacted during 2023 by the retention of a $4.2 million non-refundable third-party deposit related to the planned, but ultimately unsuccessful, disposition of non-core oil and gas properties in Northeast BC due to the purchaser's inability to meet certain closing conditions.

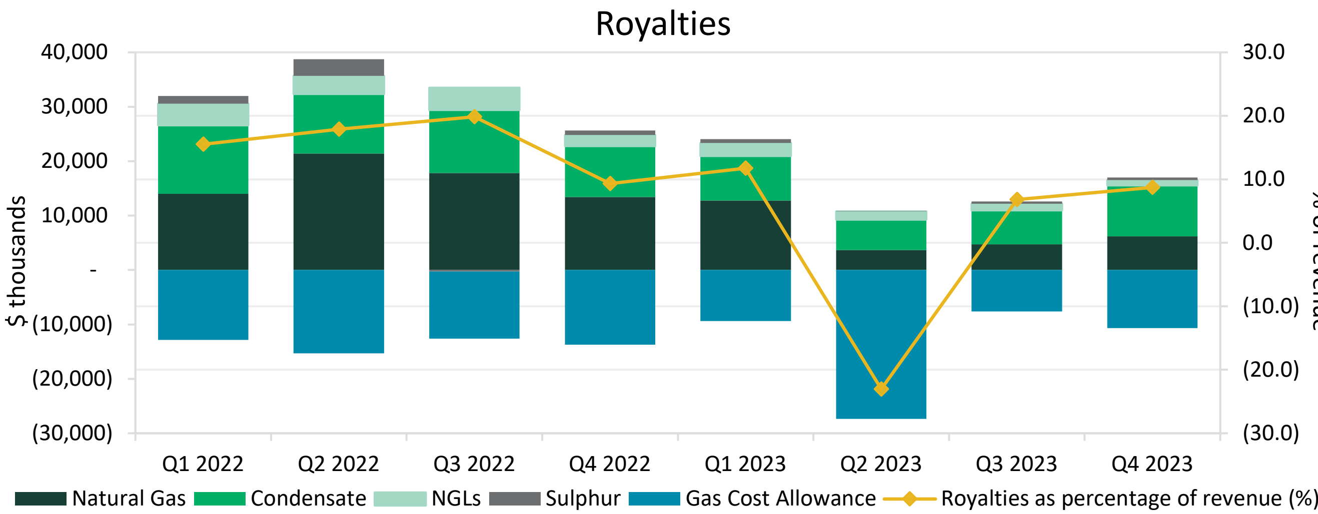
ROYALTIES

The following table summarizes the Company's royalty obligations for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Gross royalties	17,000	24,574	(31)	64,400	131,590	(51)
Gas cost allowance	(10,685)	(12,648)	(16)	(55,032)	(56,159)	(2)
Royalties	6,315	11,926	(47)	9,368	75,431	(88)
Royalties ($/boe)	2.06	3.73	(45)	0.78	5.61	(86)
Royalties as percentage of revenue (%)	9	9	-	3	16	(81)

For the three months and year ended December 31, 2023, gross royalties decreased overall and on a per boe basis due to the combination of lower pricing and lower produced volumes.

Gross natural gas royalties are reduced by Gas Cost Allowance ("GCA"), which is provided by the Alberta Crown ("Crown") to account for operating and capital expenses incurred to process and transport the Crown's royalty portion of natural gas production. For the year ended December 31, 2023, our GCA deduction was impacted by a one-time favorable adjustment of $18.0 million recorded in June 2023 related to the 2022 annual GCA calculation and resulting overpayment during 2022.



OPERATING EXPENSE

The following table summarizes the Company's operating expense for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	2023	2022	% Change	2023	2022	% Change
Operating expense	53,399	51,879	3	224,304	219,570	2
Third party processing income	(10,895)	(5,680)	92	(26,958)	(23,505)	15
Sulphur revenue	(2,663)	(4,322)	(38)	(10,417)	(23,897)	(56)
Adjusted operating expense (1)	39,841	41,877	(5)	186,929	172,168	9
Operating expense ($/boe)	17.41	16.24	7	18.75	16.32	15
Adjusted operating expense ($/boe) (1)	12.99	13.11	(1)	15.63	12.79	22

(1) Adjusted operating expense is a non-GAAP measure. Adjusted operating expense provides an industry-comparable view of the cash cost to operate our assets. Processing third-party volumes does not add materially to the cost of operating our facilities. Adjusted operating expense is calculated as operating expenses, less third-party processing revenue and sulphur revenue.

For the three months and year ended December 31, 2023, operating expenses increased by 2% and 3% respectively compared to the same periods in 2022. In December 2022, we recognized a one-time favorable adjustment related to a third-party contract associated with our operated gas processing facilities. Additionally, we recognized higher electricity usage in the fourth quarter of 2023 primarily due to higher average facility onstream factor versus the comparative period of 2022. However, power costs decreased on an annualized basis as a result of power consumption reduction and optimization efforts. We also recognized a favorable revision to carbon compliance cost estimates reflecting successful effort to reduce fuel gas usage throughout our operations.

We are committed to improving operating costs, both in aggregate and on a per boe basis through cost reduction initiatives and by increasing throughput volumes in our facilities. Our aggregate cost reduction efforts are focused on:

- Reducing fuel gas consumption in the field and in facilities. Lower fuel gas use both increases natural gas sales and decreases carbon emissions intensity and resulting carbon taxes.
- Reducing power consumption through optimization while continuing to hedge power price exposure.
- Reducing dependence on third party contractors for routine operations in our facilities by training and empowering employees.
- Centralizing contracting and procurement and deploying category management to ensure efficiencies and economies of scale in our supply chain.

The following table summarizes the Company's operating cost per boe by core area for the three months and years ended December 31, 2023 and 2022:

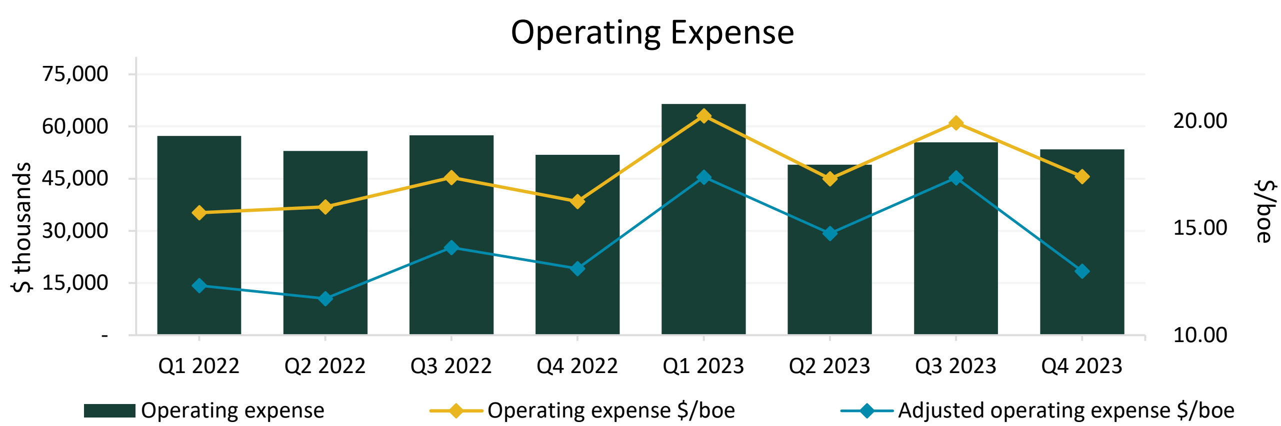
	Three months ended December 31			Year ended December 31		
($ per boe)	2023	2022	% Change	2023	2022	% Change
Waterton	14.33	15.55	(8)	18.36	13.88	32
Jumping Pound	13.65	12.67	8	15.88	13.71	16
CAB	20.44	17.68	16	19.78	19.76	-
Northern Alberta Foothills	14.35	20.60	(30)	16.68	14.47	15
Northeast BC	65.31	17.99	263	57.67	18.70	208

For the year ended December 31, 2023 our area base operating expense per boe changed as compared to 2022 for the following reasons:

- Waterton – increased due to lower volumes related to the planned but extended Waterton Turnaround.
- Jumping Pound – increased due to lower volumes as a result of unplanned maintenance.
- CAB – no change as a result of higher volumes despite unplanned maintenance.
- Northern Alberta Foothills – increased due to volume restrictions at third party facilities.
- Northeast BC – significantly increased due to lower volumes as a result of wildfires.

Adjusted Operating Expense

Adjusted operating expense reflects our view that while our three facilities are significantly more complex and costlier to operate than similar sweet-gas processing facilities, they offer acid gas extraction, deep-cut NGL recovery, NGL fractionation at two of our three major gas plants, and sulphur recovery. Significant available excess capacity also enables Pieridae to process third-party production, which materially contributes to the Company's netback. Adjusted operating expense was impacted during the three months and year ended December 31, 2023 by fluctuations in facility availability, which impacted our ability to generate revenue from these sources.

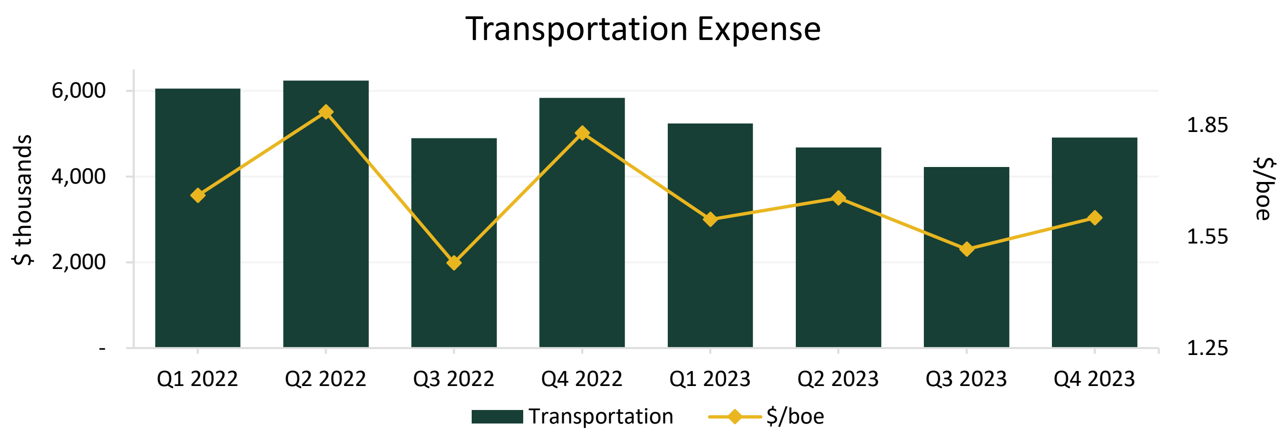


TRANSPORTATION EXPENSE

The following table summarizes the Company's transportation expense for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	2023	2022	% Change	2023	2022	% Change
Transportation expense	4,909	5,839	(16)	19,047	23,025	(17)
Transportation expense ($/boe)	1.60	1.83	(13)	1.59	1.71	(7)

Transportation expense decreased for the three months and year ended December 31, 2023 compared to the same periods in 2022 due to lower fuel cost allocations from pipeline operators, which are based on the market price of natural gas, as well as lower volumes transported.

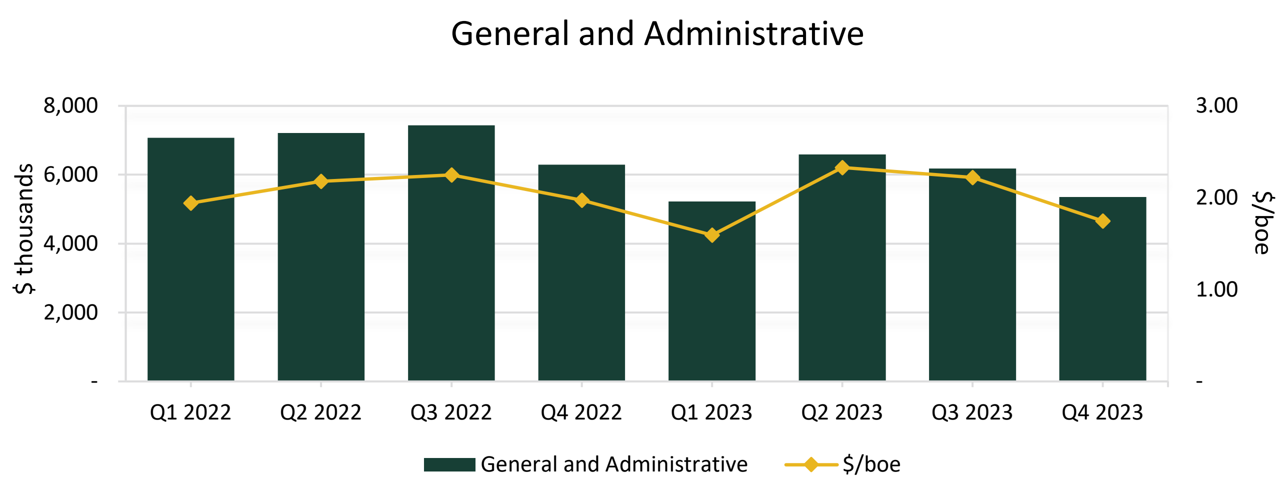


GENERAL AND ADMINISTRATIVE EXPENSE

The following table summarizes the Company's general and administrative ("G&A") expense for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
General and administrative expense	5,357	6,296	(15)	23,351	28,015	(17)
General and administrative expense ($/boe)	1.75	1.97	(11)	1.95	2.08	(6)

G&A expenses decreased in both periods of 2023, both overall and on a per boe basis, as compared to the same periods in 2022 reflecting the impact of cost reduction initiatives including the ongoing optimization of staffing levels and usage of external consultants, to ensure we operate as efficiently as possible.



FINANCE EXPENSE

The following table summarizes the Company's finance expense for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Cash portion of interest expense	5,662	4,131	37	18,174	16,440	11
Non-cash interest paid in-kind	931	3,125	(70)	6,300	13,715	(54)
	6,593	7,256	(9)	24,474	30,155	(19)
Accretion of financing costs	1,166	6,425	(82)	10,360	21,125	(51)
Loss on debt extinguishment	-	-	-	6,859	-	-
Accretion of decommissioning obligations	653	541	21	2,273	1,252	82
Interest on lease liabilities	70	49	43	245	146	68
Other charges	62	(42)	(248)	(55)	(66)	(17)
Total finance expense	**8,544**	**14,229**	**(40)**	**44,156**	**52,612**	**(16)**

On June 13, 2023, we completed a debt refinancing; as a result we recognized lower debt service costs and accretion expense associated with the new debt facilities and reduced the proportion of total interest paid-in-kind. Overall, interest expense decreased for the fourth quarter and year ended December 31, 2023 compared to the same periods in the previous year primarily due to lower overall borrowing rates. Under the new debt facilities, interest is incurred primarily in USD and is subject to fluctuations in the USD/CAD exchange rates; in the fourth quarter we initiated a currency hedge to provide downside protection on a portion of our USD denominated debt service costs. Offsetting the decrease in financing costs for the year is a one-time loss on debt extinguishment related to the retirement of our pervious term-debt.

The majority of Pieridae's interest expense for the year ended December 31, 2023 is comprised of interest on variable rate debt, the remainder being fixed rate date. Conversely, in the prior year, the entire balance was interest on fixed rate debt.

DEPLETION AND DEPRECIATION

The following table summarizes the Company's depletion and depreciation for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Depletion and depreciation	11,761	15,462	(24)	57,593	56,199	(2)

Depletion and depreciation expense decreased during the three months and year ended December 31, 2023, as compared to the same periods of 2022, as a result of a reduction in future development costs added to the depletable base.

SHARE-BASED COMPENSATION

The following table summarizes the Company's share-based compensation for the three months and year ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Share-based compensation	21	868	(98)	1,143	1,387	(18)

Our share-based compensation is comprised of expense recognized under our Stock Option Plan, Restricted Share Unit ("RSU") Plan and Deferred Share Unit ("DSU") Plan. Share based compensation expense decreased in the fourth quarter and year due primarily to a decrease in RSU expense as a result of both a decline in our share price and forfeitures. RSUs and DSUs are cash settled awards and are valued at the five-day volume-weighted average share price and the number of awards outstanding at each reporting period.

TAXES

Deferred income tax assets are recognized to the extent that the realization of the related tax benefit through future taxable profits is probable based on current tax pools and estimated future taxable income. As at December 31, 2023, a deferred tax asset in the amount of $67.9 million (December 31, 2022 – $78.9 million) was recognized as management believes it is probable that the benefit of the associated tax basis will be realized. Included in this tax basis are estimated non-capital loss carry-forwards that expire in the years 2034 through 2043.

The following table summarizes the Company's estimated tax pools at December 31, 2023 and 2022:

($ 000s)	December 31, 2023	December 31, 2022
Canadian oil and gas property expenses	158.097	174,682
Canadian development expenses	22,916	15,462
Canadian exploration expenses	23,398	14,678
Undepreciated capital costs	59,010	54,162
Non-capital losses	339,872	283,671
Other	11,617	488
Estimated tax pools	**614,910**	**543,143**

CAPITAL EXPENDITURES

The following table summarizes the Company's capital expenditures for the three months and years ended December 31, 2023 and 2022:

	Three months ended December 31			Year ended December 31		
($ 000s)	2023	2022 (1)	% Change	2023	2022 (1)	% Change
Turnarounds	4,861	3,944	23	23,190	11,767	97
Development	204	11,945	(98)	17,930	13,023	38
Facilities and well optimization	2,979	2,295	30	6,837	8,245	(17)
Facilities maintenance	812	1,621	(50)	3,586	4,250	(16)
Land	89	219	(59)	339	450	(25)
Seismic	-	-	-	200	1,700	(88)
Corporate	361	(988)	137	3,457	91	3,699
Capital expenditures	**9,306**	**19,036**	**(51)**	**55,539**	**39,526**	**41**
Reclamation and abandonment	1,592	1,614	(1)	3,118	3,791	(18)
Total capital expenditures	**10,898**	**20,650**	**(47)**	**58,657**	**43,317**	**35**

(1) Certain comparative items have been reclassified to conform to the current year's classification.

Our focus during the current reporting periods was, and continues to be, capital preservation. As a result, our capital expenditures for the fourth quarter are significantly lower than in the comparative period. For the 2022 and 2023 years, the majority of our capital spending has been on development projects and turnarounds.

Turnarounds

For the three months ended December 31, 2023, turnaround expenditures reflect trailing costs related to the Waterton Turnaround. For the same period in 2022, turnaround costs reflect unplanned maintenance at our Caroline Facility.

Turnaround costs for full year 2023 included the Waterton Turnaround, and unplanned capital maintenance at the Jumping Pound and Caroline Facilities; turnaround costs in 2022 were related to unplanned capital maintenance at our Caroline Facility.

Development

Development capital consisted primarily of the Brown Creek two-well drilling program, which commenced in the fourth quarter of 2022 and progressed through the first half of 2023, at which point we elected to defer further drilling and completion activity until natural gas prices are more supportive.

Facilities and Well Optimization

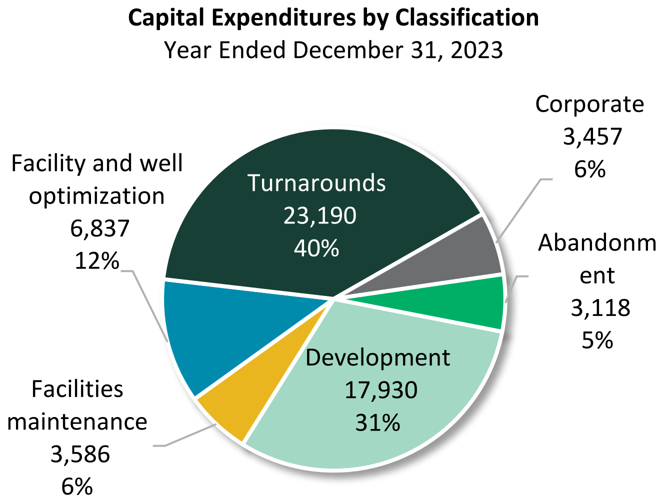
Ongoing field and facility capital optimization programs in 2022 and 2023 support mitigation of our natural reserve decline rates, and supports facility reliability.

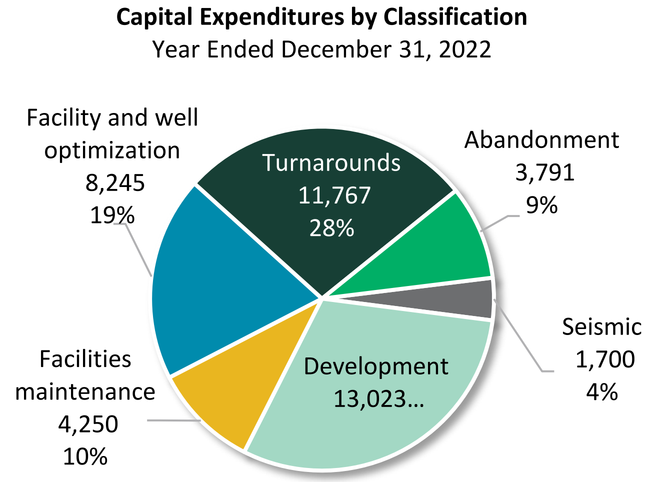
Facilities Maintenance

Facility capital maintenance expenditures decreased year-over-year as a result of ongoing optimization of our maintenance procedures as we migrated toward evidence-based activity and away from schedule-based activity.

Corporate Capital

Corporate capital expenditures are comprised of capitalized G&A and purchase of capital spares, offset in 2022 by an adjustment to capital spares inventory.





LIQUIDITY AND CAPITAL RESOURCES

Capital Resources

As at December 31, 2023, our capital structure was comprised of share capital, adjusted working capital and term debt. The following table summarizes our capital structure at December 31, 2023 and 2022:

($ 000s)	December 31, 2023	December 31, 2022
Adjusted working capital deficit (1)	(31,830)	(11,249)
Current portion of long-term debt	(30,748)	(203,254)
Long-term debt	(141,468)	-
Net debt (2)	(204,046)	(214,503)
Shareholders' equity	174,406	114,758

(1) Adjusted working capital is a non-GAAP measure and is calculated as accounts payable and accrued liabilities, less cash and cash equivalents, restricted cash, accounts receivable, prepaids and deposits.
(2) Net debt is a non-GAAP measure. Management considers net debt an important measure as it demonstrates our ability to pay off our debt and take on new debt, if necessary.

Cash and Cash Equivalents

We held $18.3 million in cash and cash equivalents and restricted cash of $0.7 million as at December 31, 2023. Restricted cash is comprised of security pledged for various letters of credit which are required to be posted with regulators, provincial agencies, and financial institutions to facilitate ongoing operations.

Guarantee Facility from Export Development Canada

In July 2020, we received a $6.0 million guarantee facility from Export Development Canada which was ultimately increased and maintained at $12.0 million. It provides 100% guarantee to the issuing banks of our existing and future letters of credit. There was $5.9 million drawn at December 31, 2023 (December 31, 2022 - $7.2 million).

Long-Term Debt

On June 13, 2023, we completed a debt refinancing. We retired our previous term-debt in advance of its maturity on October 16, 2023, in exchange for new USD $150 million and $20 million debt facilities; refer to note 11 of the Consolidated Financial Statements.

With the success of the debt refinancing, our balance sheet has improved, and we have benefited from a lower cost of capital, greater financial flexibility, and reduced financial leverage.

The new USD $150 million long-term debt facility is comprised of a USD $120 million 45-month senior facility and USD $30 million 51-month subordinated notes ("Subordinated Notes") which are both held by Pieridae Alberta Production Limited ("PAPL"), a wholly owned subsidiary of Pieridae.

The $20 million facility is an 18-month Bridge Term Loan held in Pieridae Energy Limited ("PEL") which has no direct recourse against the assets or cashflows of PAPL. As previously discussed, we intend to repay a portion, or all, of the amounts drawn under the Bridge Term Loan with cash proceeds from potential non-core divestitures. Following the conclusion of any such divestitures, we have obtained shareholder approval to convert the remaining principal amount outstanding, accrued and unpaid interest, plus a conversion fee equal to 20% of the remaining original principal outstanding, into common shares of PEL. Such conversion may occur at any point prior to maturity of the Bridge Term Loan on December 13, 2024.

The table below summarizes debt obligations as of December 31, 2023 and 2022:

($ 000s)	Principal Outstanding	December 31, 2023	December 31, 2022
Previous term loan	-	-	203,254
Senior facility			
Revolving loan USD $25,000 (1)	USD 14,800	19,574	-
Amortizing term loan USD $85,000 (1)	USD 81,600	107,924	-
Delayed draw term loan USD $10,000 (1)(2)	-	-	-
Subordinated Notes USD $30,000 (1)(3)	USD 30,000	39,678	-
PAPL total debt (3)		167,176	-
Bridge Term Loan $20,000 (4)	22,028	22,028	-
Pieridae total debt		189,204	203,254

(1) Converted to CAD using the month end exchange rate of 1.3226.
(2) The delayed draw term loan must be drawn prior to December 31, 2024. Any amount drawn will be combined with the amortizing term loan, together (the "Term Loan").
(3) Excludes unamortized deferred financing fees of $8.2 million, which includes warrants issued in concurrence with the debt refinancing.
(4) Includes interest payable in-kind of $2.0 million and excludes unamortized deferred financing fees of $0.3 million.

As a result of the refinancing, our liquidity and financial flexibility have significantly improved, with access to a revolving credit facility (59% utilized) and a delayed draw term loan (undrawn). The table below summarizes our available liquidity as of December 31, 2023 and December 31, 2022:

($ 000s)	December 31, 2023	December 31, 2022
Cash and cash equivalents	18,333	22,273
Undrawn delayed draw term loan	13,226	-
Undrawn revolving loan	13,491	-
Total available liquidity	45,050	22,273

Working Capital and Capital Strategy

The following table summarizes the Company's working capital position at December 31, 2023 and 2022:

($ 000s)	December 31, 2023	December 31,2022
Cash and cash equivalents	18,333	22,273
Restricted cash	670	670
Accounts receivable	61,523	74,514
Prepaids expenses and deposits	9,335	8,130
Total current assets	**89,861**	**105,587**
Accounts payable	44,804	22,649
Accrued liabilities	77,130	94,187
Total current liabilities	**121,934**	**116,836**
Adjusted working capital (deficit)	**(31,830)**	**(11,249)**

Our business generally operates with a sustainable working capital deficit. Our adjusted working capital deficit at December 31, 2023 increased compared to 2022; primarily driven by lower accounts receivable and revenue accruals, a slightly lower cash balance and higher accounts payable and accrued liabilities due in part to the timing of the Waterton Turnaround.

We monitor working capital on a continuous basis with a focus on strengthening our balance sheet through sustaining production, and rigorous cost control across our operations and administration. Our capital strategy is aligned with our business strategy and is focused on maintaining sufficient liquidity to fund operations, expand third party processing revenues, and partially mitigate reserves decline. Our principal sources of liquidity are the undrawn balance on our revolving loan, the undrawn balance on our delayed draw term loan, the remaining portion of the EDC guarantee facility, and any potential future debt and equity offerings.

Share Capital, Warrants and Stock Options Outstanding

	March 20, 2024	December 31, 2023	December 31, 2022
Share capital	159,099,336	159,087,336	158,963,336
Stock options	4,374,190	4,783,766	5,860,369
Stock options – weighted average exercise price ($/share)	$0.73	$0.74	$1.21
Warrants (1)	5,000,000	5,000,000	5,000,000
Warrants (1) – weighted average exercise price ($/warrant)	$0.70	$0.70	$0.70
Warrants (2)	18,596,322	18,596,322	-
Warrants (2) – weighted average exercise price ($/warrant)	$0.49	$0.49	-

(1) These warrants were issued on March 31, 2021 to the senior secured lender.
(2) These warrants were issued on June 13, 2023, with the Subordinated Notes as part of the debt refinancing.

COMMITMENTS, PROVISIONS AND CONTINGENCIES

As at December 31, 2023, our commitments and the expected timing of their settlement, are detailed below:

($ 000s)	2024	2025	2026	2027	Thereafter	Total
Firm transportation	12,415	5,782	292	-	-	18,489
Premium on foreign exchange hedges	617	-	-	-	-	617
Total	**13,032**	**5,782**	**292**	**-**	**-**	**19,106**

Provisions and Contingencies

We are involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain, we believe that any liabilities that may arise from such matters are not likely to have a material effect on the Consolidated Financial Statements.

Off Balance Sheet Transactions

We do not have any financial arrangements that are excluded from the Consolidated Financial Statements, nor are any such arrangements outstanding as of the date at this MD&A.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

We conduct our operations with high standards, aiming to meet or exceed all regulations. the Company's prime consideration is to protect our employees and consultants, the general public and the environment. Our Liability Management Rating is within both the British Columbia Energy Regulator's ("BCER"), formerly known as British Columbia Oil and Gas Commission's and the Alberta Energy Regulator's ("AER") requirements after accounting for a $1.8 million deposit in place with the BCER. Our liability rating in Alberta is calculated by the AER based on the licenses which are in Pieridae's name.

We continue to advance our ESG practices as outlined in our third annual ESG Report released on August 22, 2023. That report provides details on our approach to sustainability, GHG emissions management and to continued Indigenous and community partnerships in the areas where we operate.

We consider the impact of the changing worldwide demand for carbon-based energy and global advancement of alternative energy sources in our business strategy. Emissions and other regulations impacting climate and climate related matters are constantly evolving and we continue to monitor and implement these changes as necessary. In our ESG Report, we reported various ESG metrics referencing three international frameworks: the Sustainability Accounting Standards Board, the Task Force on Climate-Related Financial Disclosure and selected portions of the Global Reporting Initiative standards.

Our ESG work first assesses our starting point with respect to governance, GHG emissions and social policies, noting the material areas of focus. As we build on our strategic plan, we seek to evolve the business and consider energy transition and associated business opportunities. Please refer to our website for the 2023 ESG report.

RISK FACTORS

We monitor and comply with current government regulations that affect our activities, although operations may be adversely affected by changes in government policy, regulations, or taxation. In addition, we maintain a level of liability, and property and business interruption insurance, which is believed adequate for our size and activities, but we are unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims. Risk to our business and operations include, but are not limited to:

Risks Related to Pieridae's Business and Industry
Adverse Economic Conditions
Access to Capital
Liquidity
Prices, Volatility and Marketing of Oil, Natural Gas ang NGLs
Operational Matters and Hazards
Labour Relations
Development and Production
Regulatory Permits, Licenses and Approvals
Variations in Foreign Exchange and Interest Rates
Skilled Workforce
Pipeline Systems, Rail, Co-ownership of Assets, and Operational Dependence
Facilities Throughput and Utilization
Information Technology Systems and Cyber-Security
Inflation and Cost Management

Hedging Activities
Political Uncertainty and Geo-Political Risk
Project Execution
Climate Change
Climate Change – Physical Risks
Climate Change – Transition Risks
Climate Change Regulations and Carbon Pricing
Royalty Regimes
Environmental
Reputational
Third Party Credit Risk
Technological Change
Competition
Conflicts of Interest
Indigenous Land Rights Claims
Reserve Estimates
Litigation
Insurance Coverage
Breach of Confidentiality
Risks Related to Pieridae's Common Shares
Volatility
Return on Investment
Dilution

Refer to the Company's Annual Information Form for the year ended December 31, 2023, for fulsome discussion of these risks. See also "Forward Looking Statements" in this MDA.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the Consolidated Financial Statements requires management to make judgments, estimates and assumptions. These estimates and judgement are subject to change and actual results may differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The key sources of estimation uncertainty that have a significant risk of causing material adjustment to the carrying amounts of assets, liabilities, revenues and expenses are discussed below:

Identification of cash-generating units

Some of the Company's assets are aggregated into cash-generating units ("CGUs"), for the purpose of calculating depletion and impairment. A CGU is comprised of assets that are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets has occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are forecasted petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amounts of assets. Impairment charges and reversals are recognized in statements of income.

Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation ("E&E") assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing commercial viability and technical feasibility.

Lease arrangements

The Company applies judgement when reviewing each of its contractual arrangements to determine whether an arrangement contains a lease. The carrying amounts of the right-of-use assets, lease obligations, and the resulting interest and depreciation expense are based on the implicit interest rate within the lease arrangement or, if this information is unavailable, the incremental borrowing rate. Incremental borrowing rates are based on judgments including economic environment, term, and the underlying risk inherent to the asset.

Debt instruments

Debt instruments are initially recognized at fair value based on consideration received and adjusted in respect of any transaction costs that are incremental and directly attributable to the issue of the instrument. Subsequent measurement is at amortized cost and the effective interest rate method. Certain financing arrangements contain options which may revise future estimated cash outflow and result in an adjustment to the carrying value of the financial liability. At each reporting period, the Company will estimate whether such options will be exercised and if an adjustment to the financial liability is required. All adjustments arising from such changes in estimates are recognized immediately in profit or loss.

Assessment of going concern

The Company has concluded that there are no material uncertainties related to events or conditions that may cast significant doubt upon its ability to continue as a going concern. In reaching this conclusion, the Company uses significant judgement and estimates, and considered all relevant information, including feasibility of and effectiveness of management's mitigation plans. Accordingly, actual circumstances will differ from those estimates and the variation may be material.

Reserves

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological, engineering, and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's property, plant and equipment, the calculation of depletion, the provision for decommissioning obligations and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of proved and probable reserves and associated estimated cash flows are independently evaluated by qualified reserve evaluators at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum and natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered economically producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if the ability to produce is supported by either production or conclusive formation tests. The Company's petroleum and gas reserves are determined pursuant to National Instrument 51-101, Standard for Disclosures for Oil and Gas Activities.

Decommissioning obligations

The Company estimates future decommissioning and remediation costs of production facilities, processing facilities, wells and pipelines at the end of their economic lives. In most instances, abandonment and reclamation of these assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating costs, future removal technologies in determining the removal cost, inflation and liability-specific discount rates to determine present value of these cash flows.

Share-based payments

Equity-settled, share-based awards issued by the Company are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates must be made regarding the expected volatility in share price, weighted average expected life of the instrument, expected dividend yield, risk-free interest rate and estimated forfeitures at the initial grant date.

Compensation expense related to the cash-settled awards (RSUs and DSUs) is determined based on the fair value of the award at grant date and revalued at each reporting period. The valuation includes the number of awards outstanding and estimated forfeitures. Compensation expense is recognized in the statements of income with a corresponding increase or decrease in accrued liabilities. Classification of the associated short term and long-term liabilities is dependent on the expected payout dates of the awards.

Deferred taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in statements of income in the period of change, which would include any impact on cumulative provisions, and in future periods. Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amount recognized in statements of income for the period in which the change occurs.

CONTROL ENVIRONMENT

Disclosure Controls and Procedures

As of December 31, 2023, an internal evaluation was carried out of the effectiveness of the Company's disclosure controls and procedures as defined in Canada by National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Company files or submits under Canadian Securities Legislation is recorded, processed, summarized, and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Company in the reports that it files or submits under Canadian Securities Legislation is accumulated and communicated to Pieridae's Management as appropriate to allow timely decisions regarding the required disclosure.

It should be noted that while the Company's disclosure controls and procedures are intended to provide a reasonable level of assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified in securities legislation, disclosure controls and procedures cannot be expected to prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met

Internal Controls over Financial Reporting

Internal controls over financial reporting ("ICFR") is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable, and timely information. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Management has assessed the effectiveness of the Company's ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Company's ICFR was effective as of December 31, 2023. No changes were made to the Company's internal control over financial reporting during the year ended December 31, 2023, that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statements preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

NEW ACCOUNTING POLICIES

New Accounting Policies

Amendments to IAS 12 Income Taxes
On January 1, 2023, the Company adopted Deferred tax related to Assets and Liabilities Arising From a Single Transaction amendments to IAS 12 Income Taxes. These amendments require entities to recognize deferred tax on transactions, that on initial recognition, give rise to equal amounts of taxable and deductible temporary differences.

On January 1, 2023, the Company adopted the measurement and disclosure aspects of the amendment to IAS 12 International Tax Reform – Pillar Two Model Rules. This provides exception to the requirements from income tax accountability that an entity shall neither recognize, nor disclose information about deferred tax assets and liabilities related to Pillar Two income taxes.

Amendments to IAS 1 Presentation of Financial Statements
On January 1, 2023, the Company adopted the Definition of Accounting Estimates amendment to IAS 12. This amendment introduced the definition of accounting estimates to help distinguish changes in accounting estimates from changes in accounting policies.

On January 1, 2023, the Company adopted the Disclosure of Accounting Policies amendment to IAS 1. The amendments require that an entity is now required to disclose material accounting policy information instead of significant accounting policies. The amendments clarify that accounting policy information may be material because of its nature, even if the related amounts are immaterial. The accounting policy information is material if users of the financial statements would need it to understand other material information in the financial statements; and if an entity discloses immaterial accounting policy information, such information shall not obscure material accounting policy information.

Future Accounting Pronouncements

The Company plans to adopt the following amendments to accounting standards, issued by the IASB, on their respective effective dates, however, the amendments are not expected to have a material impact on the Consolidated Financial Statements.

Amendments to IAS 1 Presentation of Financial Statements
In January 2020, the IASB issued amendments to IAS 1 Presentation of Financial Statements, to clarify its requirements for the presentation of liabilities as current or non-current in the Consolidated Statements of Financial Position and clarify its requirements for the disclosure of Accounting Policies. In October 2022, the IASB issued amendments to IAS 1, which specify the classification and disclosure of a liability with covenants. Both amendments will be effective on January 1, 2024.

Amendments to IFRS 16 Lease Liability in a Sale and Leaseback
In September 2022, the IASB issued amendments to IFRS 16, Lease Liability in a Sale and Leaseback to clarify how a seller-lessee subsequently measures sale and leaseback transactions that satisfy the requirements in IFRS 15 to be accounted for as a sale. The amendment will be effective on January 1, 2024.

NON-GAAP MEASURES

Management has identified certain industry benchmarks such as NOI, operating netback, adjusted operating expense, adjusted working capital (refer to footnotes within tables of this MD&A for further information) and funds flow from operations to analyze financial and operating performance. These benchmarks are commonly used in the oil and gas industry; however, they do not have any standardized meanings prescribed by IFRS. Therefore, they may not be comparable with the calculation of similar measures for other entities.

Funds Flow from Operations

Management considers FFO an important measure to evaluate our cash flow as it demonstrates our field level operational cash flow. FFO is calculated as cash provided by operating activities, excluding settlement of decommissioning obligations and changes in non-cash working capital. Expenditures on decommissioning obligations are excluded as it is managed through the capital budgeting process.

	Three months ended December 31		Year ended December 31	
($ 000s)	**2023**	**2022**	**2023**	**2022**
Cash provided by operating activities	31,983	40,134	104,202	88,167
Settlement of decommissioning obligations	1,592	1,614	3,118	3,791
Changes in non-cash working capital	(19,306)	20,407	(21,628)	66,235
Development expense (Goldboro LNG project)	-	(4,514)	-	(4,514)
Funds flow from operations	**14,269**	**57,641**	**85,692**	**153,679**