# 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 November 8, 2023, and should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements and the accompanying notes for the three and nine months ended September 30, 2023, (the "Interim Financial Statements") and the MD&A and audited consolidated financial statements as at and for the year ended December 31, 2022 as well as Pieridae's Annual Information Form ("AIF"). The financial statements have been 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 ("NGL") 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 the Company's 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, net debt, adjusted operating expense, adjusted working capital and funds flow from operations ("FFO"). Management feels that 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, Pieridae's expected capital budget, Pieridae's future business plan and strategy, Pieridae's criteria for evaluating acquisitions and other opportunities, Pieridae's intentions with respect to future acquisitions and other opportunities, plans and timing for development of undeveloped and probable resources, timing of when the Company 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 the Company operates, 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 Pieridae's 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 Pieridae believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Pieridae 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 Pieridae operates; the timely receipt of any required regulatory approvals; the ability of Pieridae to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects which Pieridae has an interest in, to operate the field in a safe, efficient and effective manner; the ability of Pieridae 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 the ability of Pieridae 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 Pieridae operates; 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 the ability of Pieridae 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 Pieridae's 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 Pieridae's 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 Pieridae assumes 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 Pieridae's 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 Pieridae believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Pieridae is 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 | **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 operator with core assets concentrated in the Foothills of the Rocky Mountains. Our business is focused on safely developing and producing conventional raw natural gas and processing it into sales products that include natural gas liquids and sulphur. We process these commodities by using our extensive ownership in strategically located gas processing facilities in southern and central Alberta.

We are excited about our opportunities and prospects within our asset base and in the regions where we operate. We have evolved our strategy away from developing an eastern Canada liquid natural gas export facility to focus on sustaining and growing our upstream and midstream business. We will continue to mature our deep inventory of drilling prospects in the Foothills, while continuing to investigate expanding our upstream business into opportunities outside of the Foothills – in particular, where our extensive infrastructure can accommodate development by providing cost efficient egress to natural gas, condensate, natural gas liquids ("NGL"), and sulphur markets. We will achieve our objectives by developing new reserves, attracting new production volumes to our gas plants, improving netbacks, and maintaining excellent stakeholder relations.

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 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") into our business, including implementing a carbon emissions management plan targeting significant emissions intensity reductions

## QUARTERLY HIGHLIGHTS

The table below provides a summary of the consolidated financial results for the previous eight quarters:

| | 2023 | | | 2022 | | | | 2021 |
|---|---|---|---|---|---|---|---|---|
| *($ 000s unless otherwise noted)* | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 |
| **Production** | | | | | | | | |
| Natural gas (mcf/d) | 155,763 | 159,427 | 186,156 | 179,143 | 181,030 | 178,918 | 187,719 | 198,596 |
| Condensate (bbl/d) | 2,020 | 2,300 | 2,657 | 2,469 | 2,911 | 2,864 | 3,201 | 2,851 |
| NGLs (bbl/d) | 2,273 | 2,216 | 2,784 | 2,389 | 2,876 | 3,695 | 6,003 | 5,354 |
| Sulphur (tonne/d) | 1,124 | 1,362 | 1,457 | 1,348 | 1,312 | 1,555 | 1,625 | 1,185 |
| Total production (boe/d) (1) | 30,253 | 31,087 | 36,467 | 34,715 | 35,959 | 36,378 | 40,491 | 41,304 |
| **Financial** | | | | | | | | |
| **Natural Gas price ($/mcf)** | | | | | | | | |
| Realized before physical commodity contracts | 2.65 | 2.39 | 3.24 | 5.08 | 4.38 | 7.13 | 4.66 | 4.62 |
| Realized after physical commodity contracts | 3.24 | 3.00 | 5.08 | 5.24 | 3.62 | 4.67 | 4.08 | 3.67 |
| Benchmark - AECO | 2.59 | 2.40 | 3.25 | 5.20 | 4.28 | 7.22 | 4.75 | 4.69 |
| **Condensate price ($/bbl)** | | | | | | | | |
| Realized before physical commodity contracts | 97.47 | 84.81 | 107.22 | 110.24 | 103.71 | 132.60 | 112.09 | 91.69 |
| Realized after physical commodity contracts | 97.47 | 91.83 | 107.36 | 117.67 | 105.82 | 116.61 | 106.13 | 69.71 |
| Benchmark - C5 at Edmonton | 106.30 | 93.25 | 107.05 | 115.24 | 115.66 | 132.49 | 122.62 | 100.10 |
| Net income (loss) | (16,254) | 4,182 | 13,639 | 114,662 | (1,573) | 22,982 | 10,549 | 4,661 |
| Net income (loss) $ per share, basic | (0.11) | 0.03 | 0.09 | 0.72 | (0.01) | 0.15 | 0.07 | 0.03 |
| Net income (loss) $ per share, diluted | (0.11) | 0.03 | 0.08 | 0.70 | (0.01) | 0.14 | 0.07 | 0.03 |
| Net operating income (2) | 11,650 | 43,843 | 49,995 | 67,711 | 30,014 | 55,969 | 47,295 | 30,845 |
| Cashflow provided by operating activities | 7,577 | 27,533 | 37,109 | 40,134 | 9,899 | 34,922 | 3,212 | 21,139 |
| Funds flow from operations (2) | (1,422) | 35,432 | 37,413 | 57,641 | 17,721 | 43,462 | 34,855 | 12,408 |
| Total assets | 564,921 | 575,849 | 587,641 | 615,477 | 473,642 | 499,580 | 552,781 | 622,540 |
| Adjusted working capital deficit (3) | (21,454) | (6,258) | (22,275) | (11,249) | (46,419) | (28,892) | (34,934) | (61,588) |
| Net debt (2) | (205,536) | (181,670) | (202,180) | (214,503) | (254,489) | (248,967) | (273,201) | (293,169) |
| Capital expenditures | 16,363 | 9,384 | 20,486 | 19,037 | 7,216 | 9,739 | 3,534 | 1,493 |
| Development expenses (4) | - | - | - | (4,514) | - | - | - | 225 |

(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) Expenses are related to the former Goldboro LNG project.

## THIRD QUARTER 2023 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Our third quarter was highlighted by pivotal milestones as well as challenges across our business. 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 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 be instrumental in achieving our objectives. Other highlights for the quarter are as follows:

We initiated phase one of the planned major turnaround of our Waterton gas complex (the "Waterton Turnaround") in August 2023. In addition to the turnaround, extensive repairs were also made to the waste heat boiler. This planned, but extended maintenance was completed in late October 2023, which resulted in ten weeks of plant downtime representing approximately 15% and 8% of our total average production for the three and nine months ended September 30, 2023, respectively. Although these repairs have decreased production and profitability significantly for the current period, they are important to prevent future unplanned downtime due to a failure of the waste heat boiler.

During the quarter, we produced 30,253 boe/d, which is well below our production capability of approximately 37,500 boe/d and is mainly attributable to the Waterton Turnaround. We also temporarily shut-in areas within our Northeast BC and Central Alberta Foothills areas to ensure the safety of our staff and assets due to wildfire activity, but continue to forecast annual production within our previously communicated guidance. As a result of the Waterton Turnaround and the wildfires, we generated NOI of $11.7 million (netback of $4.19/boe) and negative FFO of $1.4 million. We expect production to largely recover in November.

## 2023 OUTLOOK

Our near-term priorities are to continue to strengthen our balance sheet while safely sustaining production, implementing cost reduction initiatives, optimizing infrastructure, and executing non-core asset dispositions to maintain profitability during all periods of the commodity cycle.

Forward natural gas prices have continued to experience weakness since early 2023 as global demand continues to stagnate, failing to offset higher than normal seasonal storage levels. Our robust hedge position will partially mitigate the lower expected prices through the final quarter of 2023, although not to the same extent as year to date.

2023 guidance is unchanged as follows:

| | 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) | 33,000 | 34,500 | 37,000 | 39,000 | 37,000 | 39,000 |
| Net operating income (1)(2) | 110,000 | 130,000 | 120,000 | 150,000 | 170,000 | 200,000 |
| Implied netback ($/boe) (2) | 9.00 | 11.00 | 9.00 | 11.00 | 12.00 | 14.00 |
| Sustaining capital expenditures (3) | 30,000 | 40,000 | 15,000 | 20,000 | 50,000 | 55,000 |
| Development capital expenditures (4) | 15,000 | 20,000 | 15,000 | 20,000 | 15,000 | 20,000 |

(1) Refer to the "Net Operating Income" section of this MD&A for reference to non-GAAP measures.

(2) 2023 outlook assumes average 2023 AECO price of $2.60/GJ and average 2023 West Texas Intermediate ("WTI") price of USD$74.00/bbl and accounts for hedging contracts as of September 30, 2023.

(3) Comprised of facility maintenance and turnaround capital expenditures.

(4) Comprised of seismic, development and land capital expenditures.

We are currently completing our 2024 planning process in the context of a flat to slightly stronger AECO natural gas price forecast for 2024 coupled with implementation of cost control initiatives now underway. 2024 production, net operating income and capital expenditure guidance will be announced late in the fourth quarter of 2023 once approved by the Board of Directors.

As a component of the previously announced debt refinancing, Pieridae Energy Limited. ("PEL") incurred a $20 million bridge term loan ("Bridge Term Loan") with a maturity of December 13, 2024, and an 18% compounding interest rate. We intend to repay a portion, or all, of the amounts drawn under the Bridge Term Loan with cash proceeds arising from potential non-core divestitures. Following the conclusion of any such divestitures, we plan to repay the remaining principal amount, accrued and unpaid interest plus a conversion fee equal to 20% of any remaining original principal outstanding not otherwise repaid in cash via the conversion of the amount into common shares of PEL. The conversion is to be approved by a majority of (disinterested) shareholders by special resolution or via a special meeting of shareholders prior to December 13, 2023. If shareholders agree to enact the proposed conversion feature, conversion may occur at any point from the date of shareholder approval to maturity of the Bridge Term Loan, upon 30 days notice.

## NET OPERATING INCOME

| ($ 000s) | Three months ended September 30 2023 | 2022 | % Change | Nine months ended September 30 2023 | 2022 | % Change |
|---|---|---|---|---|---|---|
| Revenue before physical commodity contracts | 64,147 | 117,586 | (45) | 220,420 | 427,809 | (48) |
| Gain (loss) on physical commodity contracts | 8,480 | (12,051) | 170 | 49,656 | (67,800) | 173 |
| Third party processing and other income | 6,752 | 7,756 | (13) | 22,944 | 21,651 | 6 |
| Realized gain (loss) on risk management contracts | (3,118) | - | (100) | 564 | - | 100 |
| Revenue | 76,261 | 113,291 | (33) | 293,584 | 381,660 | (23) |
| Royalties | (4,941) | (20,947) | (76) | (3,053) | (63,505) | (95) |
| Operating | (55,450) | (57,436) | (3) | (170,905) | (167,691) | 2 |
| Transportation | (4,220) | (4,894) | (14) | (14,138) | (17,186) | (18) |
| **Net Operating Income** [1] | **11,650** | **30,014** | **(61)** | **105,488** | **133,278** | (21) |

[1] NOI is a non-GAAP measure. Management considers NOI an important measure to evaluate operational performance as it demonstrates our field level profitability. NOI equals revenue royalties, plus realized gains (losses) on risk management contracts less operating and transportation expenses.

## NETBACK PER BOE

| ($ per boe) | Three months end September 30 2023 | 2022 | % Change | Nine months ended September 30 2023 | 2022 | % Change |
|---|---|---|---|---|---|---|
| Revenue before physical commodity contracts | 23.05 | 35.54 | (35) | 24.78 | 41.69 | (41) |
| Gain (loss) on physical commodity contracts | 3.05 | (3.64) | (184) | 5.58 | (6.61) | 184 |
| Third party processing and other income | 2.43 | 2.34 | 4 | 2.58 | 2.11 | 22 |
| Realized gain (loss) on risk management contracts | (1.12) | - | (100) | 0.06 | - | 100 |
| Revenue | 27.41 | 34.24 | (20) | 33.00 | 37.19 | (11) |
| Royalties | (1.78) | (6.33) | (72) | (0.34) | (6.19) | (95) |
| Operating | (19.92) | (17.36) | 15 | (19.22) | (16.34) | 18 |
| Transportation | (1.52) | (1.48) | 3 | (1.59) | (1.67) | (5) |
| **Netback ($/boe)** [1] | **4.19** | **9.07** | **(54)** | **11.85** | **12.99** | (9) |

[1] Netback per boe is a non-GAAP measure. Management considers netback per boe an important measure to evaluate our operational performance as it demonstrates our field level profitability relative to current commodity prices. Netback per boe equals revenue less royalties, plus realized gains (losses) on risk management contracts less operating and transportation expenses calculated on a per BOE basis.

## NET OPERATING INCOME SENSITIVITY ANALYSIS

| | Three months ended September 30 | | | | Nine months ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2023 | % Change | $ Impact | % Impact | 2023 | % Change | $ Impact | % Impact |
| **Business Environment** [1] [2] | | | | | | | | |
| WTI price (US$/bbl) [3] | 82.10 | 10 | 851 | 7 | 77.34 | 10 | 5,200 | 5 |
| AECO price ($/mcf) | 2.59 | 10 | 697 | 6 | 2.75 | 10 | 3,734 | 4 |
| Sulphur price ($/tonne) | 107.09 | 10 | 74 | 1 | 132.07 | 10 | 538 | 1 |
| US$/C$ average exchange rate [4] | 0.75 | 10 | 774 | 7 | 0.74 | 10 | 4,727 | 4 |
| **Operational** [1] [5] [6] | | | | | | | | |
| NGL & condensate production (bbl/d) | 4,293 | 10 | 1,929 | 17 | 4,746 | 10 | 8,313 | 8 |
| Natural gas production (mcf/d) | 155,763 | 10 | 1,183 | 10 | 167,004 | 10 | 5,798 | 5 |
| Sulphur production (tonne/d) | 1,124 | 10 | 128 | 1 | 1,313 | 10 | 767 | 1 |
| Royalty burden | 7% | 1 | 695 | 6 | 1% | 1 | 2,706 | 3 |
| Operating expense ($/boe) | (19.92) | 10 | 5,545 | 48 | (19.22) | 10 | 17,090 | 16 |

[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 (C2, C3, C4) and condensate (C5) prices assuming a correlation to US$WTI.
[4] Includes the impact of foreign exchange on NGL and Condensate prices assuming a correlation to US$WTI.
[5] Includes the impact of physical commodity hedges that were in place during the period.
[6] Operational assumptions are based upon the results for the three and nine months ended September 30, 2023, and the calculated impact NOI would only be applicable within a limited range of these amounts.

## PRODUCTION

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Natural gas (mcf/d) | 155,763 | 181,030 | (14) | 167,004 | 182,531 | (9) |
| Condensate (bbl/d) | 2,020 | 2,911 | (31) | 2,323 | 2,991 | (22) |
| NGLs (bbl/d) | 2,273 | 2,876 | (21) | 2,423 | 4,180 | (42) |
| Sulphur (tonne/d) | 1,124 | 1,312 | (14) | 1,313 | 1,496 | (12) |
| **Production (boe/d)** (1) | **30,253** | **35,959** | **(16)** | **32,580** | **37,593** | **(13)** |

(1) Production amounts exclude sulphur.

Production in the three and nine months ended September 30, 2023, decreased across all commodities. The main driver of the decreases was the planned, but extended, Waterton Turnaround (5,130 boe/d and 2,712 boe/d for the three and nine months ended September 30, 2023, respectively). The Waterton area is our strongest condensate producing asset, consequently, along with natural gas, the downtime has had a substantial impact on liquids production in both periods. As a result of the impact the Waterton area has on our business and the broad decreases in production across these commodities, our netbacks have been significantly affected (54% and 9% decrease for the three and nine months ended September 30, 2023).

We also shut in production in our Northeast BC area to ensure the safety of our staff and assets due to wildfires in those areas (1,448 boe/d and 923 boe/d for the three and nine months ended September 30, 2023, respectively). These production impacts were partially offset by the resumption of full production from the Limestone field, located in Central Alberta Foothills, after being partially restricted for a pipeline repair in the comparative periods (1,808 boe/d and 1,080 boe/d for the three and nine months ended September 30, 2023, respectively).

Additionally, during the three months ended September 30, 2023, our Clearwater area located in Central Alberta Foothills was shut in for seasonal maintenance (695 boe/d). During the nine months ended September 30, 2023, there were also unplanned maintenance outages at our Caroline and Jumping Pound gas processing facilities (2,230 boe/d) and our ethane volumes are now being kept in gas form and injected into the gas sales stream, versus being sold as ethane in the prior year, causing an additional decrease in NGLs for this period (1,399 boe/d).

## PRODUCTION BY AREA

The following tables summarize our production by core area for the three months ended September 30, 2023, and 2022:

| | Three months ended September 30, 2023 | | | | |
|---|---|---|---|---|---|
| | Total (boe/d) | Natural Gas (mcf/d) | Condensate (bbl/d) | NGLs (bbl/d) | Sulphur (tonne/d) |
| Waterton | 4,434 | 17,990 | 679 | 757 | 300 |
| Jumping Pound | 8,104 | 40,640 | 583 | 747 | 212 |
| Central Alberta Foothills | 14,441 | 77,528 | 752 | 768 | 604 |
| Northern Alberta Foothills | 3,254 | 19,494 | 4 | 1 | 8 |
| Northeast BC | 20 | 110 | 2 | - | - |
| **Total** | **30,253** | **155,763** | **2,020** | **2,273** | **1,124** |

| | Three months ended September 30, 2022 | | | | |
|---|---|---|---|---|---|
| | Total (boe/d) | Natural Gas (mcf/d) | Condensate (bbl/d) | NGLs (bbl/d) | Sulphur (tonne/d) |
| Waterton | 9,563 | 40,631 | 1,483 | 1,308 | 640 |
| Jumping Pound | 7,856 | 39,585 | 541 | 718 | 197 |
| Central Alberta Foothills | 14,183 | 74,975 | 839 | 848 | 465 |
| Northern Alberta Foothills | 3,366 | 20,141 | 7 | 2 | 10 |
| Northeast BC | 991 | 5,698 | 41 | - | - |
| **Total** | **35,959** | **181,030** | **2,911** | **2,876** | **1,312** |

The following tables summarize our production by core area for the nine months ended September 30, 2023, and 2022:

| | Nine months ended September 30, 2023 | | | | |
|---|---|---|---|---|---|
| | Total (boe/d) | Natural Gas (mcf/d) | Condensate (bbl/d) | NGLs (bbl/d) | Sulphur (tonne/d) |
| Waterton | 7,576 | 31,932 | 1,183 | 1,072 | 501 |
| Jumping Pound | 6,848 | 34,240 | 482 | 659 | 185 |
| Central Alberta Foothills | 14,525 | 79,240 | 628 | 690 | 620 |
| Northern Alberta Foothills | 3,224 | 19,308 | 4 | 2 | 7 |
| Northeast BC | 407 | 2,284 | 27 | - | - |
| **Total** | **32,580** | **167,004** | **2,324** | **2,423** | **1,313** |

| | Nine months ended September 30, 2022 | | | | |
|---|---|---|---|---|---|
| | Total (boe/d) | Natural Gas (mcf/d) | Condensate (bbl/d) | NGLs (bbl/d) | Sulphur (tonne/d) |
| Waterton | 10,239 | 40,655 | 1,527 | 1,936 | 649 |
| Jumping Pound | 8,085 | 38,832 | 559 | 1,054 | 211 |
| Central Alberta Foothills | 14,615 | 75,485 | 851 | 1,184 | 627 |
| Northern Alberta Foothills | 3,615 | 21,604 | 8 | 6 | 9 |
| Northeast BC | 1,039 | 5,955 | 46 | - | - |
| **Total** | **37,593** | **182,531** | **2,991** | **4,180** | **1,496** |

## BENCHMARK PRICES

| | | | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|---|
| | Q3 2023 | Q3 2022 | % Change | Q2 2023 | 2023 | 2022 | % Change |
| **Natural Gas** | | | | | | | |
| AECO ($/mcf) | 2.59 | 4.28 | (39) | 2.40 | 2.75 | 5.41 | (49) |
| Henry Hub (USD/MMbtu) | 2.58 | 7.94 | (67) | 2.13 | 2.46 | 6.66 | (63) |
| Differential AECO-NYMEX Premium/(Discount) (USD/MMbtu) | (0.65) | (4.66) | (86) | (0.34) | (0.42) | (2.43) | (83) |
| **Condensate** | | | | | | | |
| C5 at Edmonton ($/bbl) | 106.30 | 115.66 | (8) | 93.25 | 102.20 | 123.56 | (17) |
| Differential C5-WTI Premium/(Discount) (USD/bbl) | (2.75) | (3.09) | (11) | (4.35) | (1.38) | (1.76) | (22) |
| West Texas Intermediate crude oil (USD/bbl) | 82.10 | 92.18 | (11) | 73.71 | 77.34 | 98.62 | (22) |
| Sulphur ($/tonne) | 107.09 | 222.44 | (52) | 114.92 | 132.07 | 395.61 | (67) |
| US-Canadian dollar average exchange rate | 0.7455 | 0.7659 | (3) | 0.7447 | 0.7432 | 0.7795 | (5) |

We currently sell into the TC NGTL system with 100% of our natural gas production priced at AECO. AECO pricing is derived from Henry Hub pricing less an AECO basis differential. Henry Hub prices modestly increased during the third quarter of 2023 as compared to the second quarter of 2023 due to a decrease in US active rig counts related to continued weak pricing and seasonally strong US demand. AECO pricing followed the Henry Hub increase with strong demand and a refill of storage in the Alberta market. For the three and nine months ended September 30, 2023, AECO and Henry Hub prices decreased significantly, compared with the historically high prices during the same periods of 2022. AECO differentials relative to NYMEX is an important benchmark to our business because it uses the Henry Hub benchmark to price the futures contract. The AECO-NYMEX differential for the three months ended September 30, 2023, remained consistent compared with the second quarter of 2023 and narrowed significantly compared with the three and nine months ended September 30, 2022.

We primarily sell our produced condensate into the Edmonton market for use as diluent; condensate pricing is highly correlated to the WTI crude oil price as it is used as diluent to reduce the viscosity of oil for transportation through pipelines. In the third quarter of 2023, C5 and WTI crude oil prices recovered compared with the second quarter of 2023 as globally observed inventories fell to their lowest level in over a year due to production cuts by Saudi Arabia which have been extended through to the end of 2023. Third quarter C5 and WTI pricing were lower than the comparative three and nine month periods of 2022 as a result of supply and demand imbalances due to geopolitical tension with Russia. For the three and nine months ended September 30, 2023, the condensate differential to WTI narrowed relative to all comparative periods as a result of seasonally higher diluent demand.

Our sulphur production is sold into a variety of markets including directly to North American fertilizer manufacturers as well as international markets through the Vancouver or Tampa Bay sulphur export facilities. Sulphur benchmark prices continued to decline when compared to all comparative quarters. 2022 was a year of extreme price volatility in the sulphur markets with west coast benchmark prices ranging from $89/tonne to $601/tonne within the year. 2023 sulphur price volatility is somewhat lower with year-to-date west coast benchmark prices ranging from a low of $85/tonne to a high of $224/tonne.

## REALIZED PRICES

| | | | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|---|
| | Q3 2023 | Q3 2022 | % Change | Q2 2023 | 2023 | 2022 | % Change |
| **Realized Natural Gas Price** | | | | | | | |
| Before physical commodity contracts ($/mcf) | 2.65 | 4.38 | (39) | 2.39 | 2.79 | 5.37 | (48) |
| After physical commodity contracts ($/mcf) | 3.24 | 3.62 | (10) | 3.00 | 3.84 | 4.12 | (7) |
| **Realized Condensate Price** | | | | | | | |
| Before physical commodity contracts ($/bbl) | 97.47 | 103.71 | (6) | 84.81 | 96.97 | 115.89 | (16) |
| After physical commodity contracts ($/bbl) | 97.47 | 105.82 | (8) | 91.83 | 99.34 | 109.37 | (9) |
| NGLs ($/bbl) | 31.87 | 46.31 | (31) | 32.09 | 36.51 | 40.17 | (9) |
| Sulphur ($/tonne) | 13.34 | 38.79 | (66) | 22.78 | 21.63 | 47.93 | (55) |

Our realized prices reflect the mix of spot sales and physical forward sales contracts consistent with our hedging policy. For the nine months ended September 30, 2023, volumes sold under physical forward sales contracts represented 41% of production and 48% of revenue (Nine months ended September 30, 2022, volumes sold under physical forward sales contracts represented 52% of production and 65% of revenue).

We are obligated to sell the majority of our sulphur production for CAD $6.00/tonne under a fixed-price physical sales contract which expires on December 31, 2025. This contract represented 79% and 78% of sulphur volumes for the three and nine months ended September 30, 2023, respectively (83% and 81% for the three and nine months ended September 30, 2022 respectively). If the fixed-priced sulphur sales contracts were removed, average realized sulphur prices for the three and nine months ended September 30, 2023, would have been $87.63/tonne and $41.94/tonne respectively (net of transportation and based on contracted prices that are negotiated annually).

## RISK MANAGEMENT CONTRACTS

Our risk management program is governed by our hedge policy and, as of September 30, 2023, we are hedged in accordance with the thresholds in our senior loan agreement, which averages approximately 52% of our proved developed producing natural gas and condensate production net of annualized royalties from 2024 to 2027.

Financial risk management contracts are considered derivative financial instruments and 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 if hedge accounting is applied. 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 September 30, 2023.

We had the following fixed price physical commodity sales contracts and power contracts in place on September 30, 2023:

| Type of contract | Quantity | Time Period | Contract Price |
|---|---|---|---|
| Fixed Price – Natural Gas Sales | 50,000 GJ/d | Oct 2023 | CAD $4.38/GJ |
| Fixed Price – Natural Gas Sales | 20,000 GJ/d | Nov 2023 – 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 – AECO/Nymex Differential | 7,500 Mmbtu/d | Oct 2023 | USD $(1.15)/Mmbtu |
| Fixed Price – Power Purchases | 55 MW/h | Oct 2023 – Dec 2023 | CAD $71.80/MWh |
| 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 | 47 MW/h | Jan 2026 – Dec 2026 | CAD $75.88/MWh |
| Fixed Price – Power Purchases | 11 MW/h | Jan 2027 – Dec 2027 | CAD $75.10/MWh |

We had the following financial risk management contracts in place as at September 30, 2023:

| Type of contract | Quantity | Time Period | Contract Price |
|---|---|---|---|
| AECO Natural Gas Swap | 30,000 GJ/d | Oct 2023 | CAD $1.89/GJ |
| AECO Natural Gas Swap | 30,000 GJ/d | Oct 2023 – May 2026 | CAD $3.10/GJ |
| AECO Natural Gas Swap | 50,000 GJ/d | Nov 2023 – May 2026 | CAD $3.30/GJ |
| AECO Natural Gas Swap | 25,000 GJ/d | Nov 2023 – 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 | 1,685 bbl/d | Oct 2023 – Dec 2023 | CAD $80.00 - $90.75/bbl |
| WTI Crude Oil Collar | 1,405 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 – Dec 2027 | CAD $80.00 - $90.75/bbl |
| WTI Crude Oil Swap | 70 bbl/d | Nov 3023 – Dec 2023 | CAD $120.00/bbl |
| WTI Crude Oil Swap | 30 bbl/d | Nov 2023 – Dec 2024 | CAD $110.25/bbl |
| WTI Crude Oil Swap | 70 bbl/d | Nov 2023 – 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 |

Subsequent to quarter end, Pieridae entered into a currency hedge for the next twelve months, which provides the right but not the obligation to purchase USD at a fixed exchange rate in exchange for a deferred option premium. This provides downside protection on currency fluctuations between USD and CAD while allowing full upside participation. The majority of the Company's debt is denominated in USD.

## PETROLEUM AND NATURAL GAS REVENUE

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s except per boe)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Natural gas | 46,468 | 60,252 | (23) | 175,166 | 205,279 | (15) |
| Condensate | 18,115 | 28,345 | (36) | 63,011 | 89,316 | (29) |
| NGLs | 6,664 | 12,256 | (46) | 24,145 | 45,839 | (47) |
| Sulphur | 1,380 | 4,682 | (71) | 7,754 | 19,575 | (60) |
| **Petroleum and natural gas revenue** (1) | **72,627** | **105,535** | **(31)** | **270,076** | **360,009** | **(25)** |
| Petroleum and natural gas revenue ($/boe) | 26.09 | 31.90 | (18) | 30.36 | 35.08 | (13) |
| Third party processing and other income | 6,752 | 7,756 | (13) | 22,944 | 21,651 | 6 |
| Realized gain (loss) on risk management contracts | (3,118) | - | (100) | 564 | - | 100 |
| **Revenue** | **76,261** | **113,291** | **(33)** | **293,584** | **381,660** | **(23)** |

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

Our revenue is derived from the sale of natural gas, NGL and sulphur production. Fluctuations in our revenue are dependent on the commodity prices we receive for our production. Prices are market driven and fluctuate due in part to factors that are not under our control beyond exposure reduction implemented through our hedge policy. Petroleum and natural gas revenue decreased for the three and nine months ended September 30, 2023, compared to the same periods of 2022, which is attributable to the decrease in production.

Third party processing and other income is primarily derived from fees charged to non-owner third parties for processing their production and sulphur volumes through our gas processing facilities. The majority of the change in the three months ended September 30, 2023, can be attributed to the fact that during 2022, we earned a marketing fee adjustment associated with the change in our operations requiring us to reinject ethane back into the gas sales stream at the Waterton and Jumping Pound facilities, which ended in December 2022.

Third party processing and other income during the nine months ended September 30, 2023, includes $4.2 million due to our retention of a non-refundable third-party deposit related to a planned disposition of non-core oil and gas properties in Northeast BC. The deposit was retained following failure by the third party to meet certain conditions required to close the transaction. This is partially offset by the unplanned maintenance related to condenser repairs at our Jumping Pound gas processing facility, the Waterton Turnaround and reduced volumes being trucked-in in our Central Alberta Foothills area, together $2.5 million.

During the three and nine months ended September 30, 2023, we recorded a loss and a gain, respectively, on our risk management contracts We actively mitigate our exposure to commodity price and foreign exchange fluctuations through risk management contracts. During the nine months ended September 30, 2023, we recognized a benefit of $1.8 million by monetizing an existing commodity risk management contract, and a benefit of $1.5 million on the closure of a foreign exchange risk management contract.

## ROYALTIES

| ($ 000s except per boe) | Three months ended September 30 2023 | 2022 | % Change | Nine months ended September 30 2023 | 2022 | % Change |
|---|---|---|---|---|---|---|
| Gross royalties | 12,572 | 33,240 | (62) | 47,399 | 103,959 | (54) |
| Gas cost allowance | (7,631) | (12,293) | (38) | (44,346) | (40,454) | 10 |
| Royalties | 4,941 | 20,947 | (76) | 3,053 | 63,505 | (95) |
| Royalties ($/boe) | 1.78 | 6.33 | (72) | 0.34 | 6.19 | (95) |
| Royalties as percentage of revenue (%) | 7 | 20 | (65) | 1 | 18 | (94) |

For the three and nine months ended September 30, 2023, gross royalties decreased in both periods due to lower production volumes. For the nine months ended September 30, 2023, net royalties were impacted by a one-time favorable adjustment to the 2022 Gas Cost Allowance credit which is calculated annually by the Alberta Crown and applied against the current year's crown royalty expense.

## OPERATING EXPENSE

| ($ 000s except per boe) | Three months ended September 30 2023 | 2022 | % Change | Nine months ended September 30 2023 | 2022 | % Change |
|---|---|---|---|---|---|---|
| Operating expense | 55,450 | 57,436 | (3) | 170,905 | 167,691 | 2 |
| Operating expense ($/boe) | 19.92 | 17.36 | 15 | 19.22 | 16.34 | 18 |
| Adjusted operating expense (1) | 48,289 | 46,614 | 4 | 147,088 | 130,290 | 13 |
| Adjusted operating expense ($/boe) (1) | 17.35 | 14.09 | 23 | 16.54 | 12.70 | 30 |

(1) Adjusted operating expense is a non-GAAP measure. Adjusted operating expense provides an industry-comparable view of operating expenses for our sour gas processing facilities by accounting for all third-party volumes running through these facilities. Adjusted operating expense is calculated as operating expenses, less third-party processing revenue and sulphur revenue.

We continue to maintain our focus on cost control and mitigating the impacts of inflation. A major part of our cost control initiatives includes a physical hedge program that is in place for the majority of our power consumption which substantially mitigates higher power prices. We are also able to sell any unused power back to the market during facility downtime, which periodically offsets our power costs.

During the three months ended September 30, 2023, operating expenses decreased moderately from the comparative period, due to reduced power consumption related to the Waterton Turnaround. This decrease was partially offset by the Alberta Technology Innovation and Emissions Reduction ("TIER") compliance cost estimate, which increased to $65/t CO2e from $50/t CO2e from 2022, and increased field maintenance work concurrent with the Waterton Turnaround.

During the nine months ended September 30, 2023, operating expenses increased marginally from the comparative period primarily due to higher TIER compliance cost estimates partially offset by decreased costs of power, which includes a power hedging gain related to lower consumption.

During the three and nine months ended September 30, 2023, as compared to the same periods in 2022, operating expenses are higher on a per boe basis due to lower production volumes related to the Waterton Turnaround, the wildfires in Northeast BC and the high fixed-cost component of our gas processing facilities.

Adjusted operating expense reflects our view that the net operating costs of our three major sour gas processing facilities which process third party volumes and are significantly more complex than similar sweet-gas facilities. Adjusted operating expense was higher for the three and nine months ended September 30, 2023, reflecting lower third-party volumes processed during the periods due to the previously mentioned facilities outages.

The following table summarizes our operating cost per boe by core area for the three and nine months ended September 30, 2023, and 2022:

| ($ per boe) | Three months ended September 30 2023 | 2022 | % Change | Nine months ended September 30 2023 | 2022 | % Change |
|---|---|---|---|---|---|---|
| Waterton | 33.66 | 15.19 | 122 | 19.59 | 13.40 | 46 |
| Jumping Pound | 13.66 | 13.99 | (2) | 16.72 | 14.06 | 19 |
| Central Alberta Foothills | 18.84 | 21.53 | (12) | 19.55 | 20.40 | (4) |
| Northern Alberta Foothills | 17.78 | 12.35 | 44 | 17.53 | 12.60 | 39 |
| Northeast BC | 631.45 | 22.50 | 2,706 | 55.60 | 18.94 | 194 |

The following table summarizes our adjusted operating cost per boe by core area for the three and nine months ended September 30, 2023, and 2022:

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ per boe)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Waterton | 32.24 | 13.19 | 144 | 18.25 | 10.53 | 73 |
| Jumping Pound | 18.87 | 9.16 | 106 | 11.92 | 9.03 | 32 |
| Central Alberta Foothills | 11.23 | 17.39 | (35) | 16.53 | 16.03 | 3 |
| Northern Alberta Foothills | 16.79 | 11.78 | 43 | 17.42 | 11.74 | 48 |
| Northeast BC | 47.51 | 22.50 | 111 | 55.60 | 18.94 | 194 |

## TRANSPORTATION EXPENSE

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s except per boe)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Transportation expense | 4,220 | 4,894 | (14) | 14,138 | 17,186 | (18) |
| Transportation expense ($/boe) | 1.52 | 1.48 | 3 | 1.59 | 1.67 | (5) |

Transportation expense decreased for the three and nine months ended September 30, 2023, compared to the same periods in 2022, primarily due to lower fuel cost allocations from the pipeline operators, which are based on the market price of natural gas.

## GENERAL AND ADMINISTRATIVE EXPENSE

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s except per boe)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| G&A expense | 6,178 | 7,433 | (17) | 17,994 | 21,719 | (17) |
| G&A expense ($/boe) | 2.22 | 2.25 | (1) | 2.02 | 2.12 | (5) |

General and administrative ("G&A") expense for the three and nine months ended September 30, 2023, decreased in both periods primarily due to lower insurance expense allocated to G&A and our continued cost control initiatives.

## FINANCE EXPENSE

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Cash portion of interest expense | 5,503 | 3,839 | 43 | 12,512 | 12,309 | 2 |
| Non-cash interest paid in kind | 927 | 3,259 | (72) | 5,369 | 10,590 | (49) |
| | 6,430 | 7,098 | (9) | 17,881 | 22,899 | (22) |
| Accretion on financing costs | 1,155 | 3,484 | (67) | 9,194 | 14,700 | (37) |
| Loss on debt extinguishment | - | - | - | 6,859 | - | 100 |
| Accretion of decommissioning obligations | 558 | 525 | 6 | 1,620 | 711 | 128 |
| Interest on lease liabilities | 65 | 39 | 67 | 174 | 100 | 74 |
| Other charges | (38) | (119) | (68) | (116) | (27) | 330 |
| **Total finance expense** | **8,170** | **11,027** | **(26)** | **35,612** | **38,383** | **(7)** |

On June 13, 2023, we completed a debt refinancing; as a result, there were lower fees and accretion associated with the new debt. There were also significant changes to the treatment of interest expense, which is now mainly settled in cash rather than being paid in-kind. Overall, interest expense decreased for the three and nine months ended September 30, 2023, because the borrowing rate on the new debt is significantly lower than the previous term-debt. While interest expense is still lower than the comparative periods, the entire amount of cash interest expense is related to USD denominated debt and is subject to changes in the USD-CAD exchange rates, which have become increasingly unfavourable since we completed our debt refinancing. Subsequent to September 30, 2023, we have initiated a currency hedge to provide downside protection on our USD denominated debt.

## DEPLETION AND DEPRECIATION

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Depletion and depreciation | 12,986 | 12,770 | 2 | 45,832 | 40,737 | 13 |

Depletion and depreciation expense increased for the three and nine months ended September 30, 2023, compared with the same periods of 2022, due to an increase in the depletion rate, which arose from higher expected future development costs within our total proved and probable reserve value. Additional depletion was also recorded on assets held for sale that were reclassified back into property, plant and equipment in June 2023.

## CAPITAL EXPENDITURES

| | Three months ended September 30 | | | Nine months ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ 000s)* | 2023 | 2022 | % Change | 2023 | 2022 | % Change |
| Seismic | - | - | - | 200 | 1,700 | (88) |
| Development | 1,765 | 3,108 | (43) | 21,584 | 7,029 | 207 |
| Land | 82 | 111 | (26) | 250 | 228 | 10 |
| Plant and facilities | 2,224 | 1,220 | 82 | 2,774 | 2,738 | 1 |
| Turnarounds | 11,692 | 2,149 | 444 | 18,329 | 7,821 | 134 |
| Corporate | 600 | 628 | (4) | 3,096 | 973 | 218 |
| **Capital expenditures** | **16,363** | **7,216** | **127** | **46,233** | **20,489** | **126** |
| Abandonment | 639 | 541 | 18 | 1,527 | 2,177 | (30) |
| **Total capital expenditures** | **17,002** | **7,757** | **119** | **47,760** | **22,666** | **111** |

Third quarter capital expenditures reflect expenditures related to the Waterton Turnaround and costs associated with the repairs and re-tubing of the waste heat boiler. Expenditures for the first nine months of 2023 reflect the Waterton Turnaround, the development program in Brown Creek and the repairs to sulphur condensers in both the Jumping Pound and Caroline gas facilities.

## LIQUIDITY AND CAPITAL RESOURCES

### Capital Resources

As at September 30, 2023, our capital structure was comprised of share capital, adjusted working capital and term debt. The following table summarizes our capital structure on September 30, 2023, and December 31, 2022:

| *($ 000s)* | September 30, 2023 | December 31, 2022 |
|---|---|---|
| Adjusted working capital (deficit) [(1)] | (21,454) | (11,249) |
| Current portion of long-term debt | (9,194) | (203,254) |
| Long-term debt | (174,888) | - |
| Net debt [(2)] | **(205,536)** | (214,503) |
| Shareholders' equity | **108,485** | 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 $13.7 million in cash and cash equivalents and $0.7 million of restricted cash as at September 30, 2023. Restricted cash is comprised of security pledged for various letters of credit which are required to be posted with provincial agencies and other companies to facilitate our ongoing operations.

### Guarantee Facility from Export Development Canada ("EDC")

In July 2020, we received a $6.0 million guarantee facility from Export Development Canada which was ultimately increased to $12.0 million and was renewed for that amount effective June 2023. It provides 100% guarantee to the issuing banks of our existing and future letters of credit. $6.4 million was drawn at September 30, 2023 (December 31, 2022 - $7.2 million).

## Long-Term Debt

On June 13, 2023, we completed our debt refinancing. We retired our existing term-debt in advance of its maturity on October 16, 2023, in exchange for new USD $150 million (USD $134.1 million drawn) and $20 million ($20 million drawn) long term debt facilities; refer to note 6 of the Interim Financial Statements.

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

The 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 Pieridae.

The $20 million facility is an 18-month Bridge Term Loan held in PEL and 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 arising from potential non-core divestitures. Following the conclusion of any such divestitures, in order to provide increased flexibility, PEL has agreed to seek shareholder approval, by December 13, 2023, to permit the conversion of the remaining principal amount, accrued and unpaid interest plus a conversion fee equal to 20% of the original principal outstanding into common shares of PEL. From the date of shareholder approval until the maturity of the Bridge Term Loan, the conversion feature may be exercised. If shareholder approval is not obtained, the Bridge Term Loan will continue to be repayable in cash in accordance with its original terms, and along with the Subordinated Notes, will be subject to an increase to interest rates of 10% and 2% per annum, respectively.

The table below summarizes debt obligations as of September 30, 2023, as compared to December 31, 2022:

| *($ 000s)* | **Principal Outstanding** | **September 30, 2023** | **December 31, 2022** |
|---|---|---|---|
| Previous term loan | | - | 203,254 |
| Senior facility | | | |
| Revolving loan USD $25,000 (1) | USD 20,800 | 28,122 | - |
| Amortizing term loan USD $85,000 1) | USD 83,300 | 112,622 | - |
| Delayed draw term loan USD $10,000 (1)(2) | - | **-** | - |
| Subordinated Notes USD $30,000 (1) | USD 30,000 | 40,430 | - |
| PAPL total debt (3) | | **181,174** | 203,254 |
| Bridge Term Loan $20,000 (4) | 21,097 | 21,097 | - |
| Pieridae total debt | | **202,271** | 203,254 |

(1) Converted to CAD using the month end exchange rate of 1.352.

(2) The delayed draw term loan must be drawn between July 1, 2023, and 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 $0.6 million and fair value of warrants of $7.2 million.

(4) Includes interest payable in kind of $1.1 million and excludes unamortized deferred financing fees of $0.3 million.

As a result of the refinancing, our liquidity and financial flexibility is improved, with access to a revolving credit facility (83% utilized) and a delayed draw term loan (undrawn). The table below summarizes our available liquidity as of September 30, 2023, as compared to December 31, 2022:

| *($ 000s)* | **September 30, 2023** | **December 31, 2022** |
|---|---|---|
| Cash and cash equivalents | **13,747** | 22,273 |
| Undrawn delayed draw term loan | **13,520** | - |
| Undrawn senior revolver | **5,678** | - |
| Total available liquidity | **32,945** | 22,273 |

### Working Capital and Capital Strategy

The following table presents the composition of our working capital position at September 30, 2023, and December 31, 2022:

| *($ 000s)* | September 30, 2023 | December 31, 2022 |
|---|---|---|
| Cash and cash equivalents | 13,747 | 22,273 |
| Restricted cash | 670 | 670 |
| Accounts receivable | 52,466 | 74,514 |
| Prepaids expenses and deposits | 8,330 | 8,130 |
| **Total current assets** | **75,213** | **105,587** |
| Accounts payable | 16,860 | 22,649 |
| Accrued liabilities | 79,807 | 94,187 |
| **Total current liabilities** | **96,667** | **116,836** |
| **Adjusted working capital (deficit)** | **(21,454)** | **(11,249)** |

Our business generally operates with a sustainable working capital deficit based on the time to convert our assets and liabilities to cash. Our adjusted working capital deficit at September 30, 2023 increased compared to December 31, 2022 driven by lower cash, accounts receivable and revenue accruals due to lower production and continued weak natural gas pricing. This increase in adjusted working capital deficit was partially offset by lower accounts payable and accrued liabilities.

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 and partially mitigate reserves decline. Our principal sources of liquidity are the undrawn balance on our senior secured revolving loan (USD $4.2 million), the undrawn balance on our senior secured delayed draw term loan (USD $10 million), the remaining portion of the EDC guarantee facility ($5.6 million), and additional debt and equity offerings.

## SHARE CAPITAL, WARRANTS AND STOCK OPTIONS OUTSTANDING

| | November 8, 2023 | September 30, 2023 | December 31, 2022 |
|---|---|---|---|
| Share capital | 159,066,336 | 159,008,336 | 158,963,336 |
| Stock options | 5,984,779 | 6,083,779 | 5,860,369 |
| Stock options – weighted average exercise price ($/share) | $0.76 | $0.76 | $1.21 |
| Warrants | 5,000,000 | 5,000,000 | 5,000,000 |
| Warrants – weighted average exercise price ($/warrant) | $0.70 | $0.70 | $0.70 |
| Warrants[1] | 18,596,322 | 18,596,322 | - |
| Warrants[1] – weighted average exercise price ($/warrant) | $0.49 | $0.49 | - |

[1] These warrants were issued on June 13, 2023, with the Subordinated Notes as a part of the debt refinancing.

## COMMITMENTS, PROVISIONS AND CONTINGENCIES

We have entered into several firm transportation arrangements during the normal course of business. As at September 30, 2023, these arrangements, and the expected timing of their settlement, are detailed below:

| *($ 000s)* | 2023 | 2024 | 2025 | 2026 | Thereafter | Total |
|---|---|---|---|---|---|---|
| Firm transportation | 2,834 | 11,302 | 4,627 | 253 | - | 19,016 |

#### 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 Interim Financial Statements.

#### Off Balance Sheet Transactions

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

## ENVIRONMENT SOCIAL AND GOVERNANCE

We conduct our operations with high standards, aiming to meet or exceed all regulations. Pieridae'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, greenhouse gas 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, greenhouse gas 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 to be 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 |
| Price, Volatility and Marketing of Oil, Gas and NGLs |
| Access to Capital |
| Liquidity |
| Operational Matters and Hazards |
| Labour Relations |
| Development and Production |
| Regulatory Permits, Licenses and Approvals |
| Political Uncertainty and Geo-Political Risk |
| Skilled Workforce |
| Facilities Throughput and Utilization |
| Pipeline Systems, Rail, Co-ownership of Assets, and Operational Dependence |
| Information Technology Systems and Cyber-Security |
| Inflation and Cost Management |
| Hedging Activities |
| Climate Change |
| Climate Change - Physical Risks |
| Climate Change - Transition Risks |
| Climate Change Regulations and Carbon Pricing |
| Variations in Foreign Exchange and Interest Rates |
| Royalty Regimes |
| Project Execution |
| Environmental |
| Third Party Credit Risk |
| Technological Change |
| Competition |
| Conflicts of Interest |
| Indigenous Land and Rights Claims |
| Reserve Estimates |
| Litigation |
| Insurance Coverage |
| Breach of Confidentiality |
| Reputational |
| **Risks Related to Pieridae's Common Shares** |
| Volatility |

| |
|---|
| Return on Investment |
| Dilution |

Refer to our Annual Information Form for the year ended December 31, 2022, for fulsome discussion of these risks. See also "Forward Looking Statements" in this MDA.

## SIGNIFICANT ACCOUNTING JUDGEMENT AND ESTIMATES

The timely preparation of the Interim Financial Statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The use of significant judgments and estimates made by management in the preparation of the Interim Financial Statements are discussed in note 2 of the consolidated financial statements for the year ended December 31, 2022.

## CONTROL ENVIRONMENT

**Disclosure Controls and Procedures and Internal Controls over Financial Reporting**

We are required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings." The certification of interim filings for the period ended September 30, 2023, requires that we disclose in the interim MD&A any changes in disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICFR) that occurred during the period that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting. No such changes were made to our DC&P and ICFR during the period ended September 30, 2023.

## NEW ACCOUNTING POLICIES

We have not adopted any new accounting policies in the current period. Further, there are currently no not-yet-effective IFRS or IFRIC interpretations that are expected to have a material impact on our financial information.

## NON-GAAP MEASURES

Management has identified certain industry benchmarks such as NOI, netback, adjusted operating expense, adjusted working capital (refer to footnotes within tables of this MD&A for further information) and FFO 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 September 30 | | Nine months ended September 30 | |
|---|---|---|---|---|
| *($ 000s)* | **2023** | **2022** | **2023** | **2022** |
| Cash provided by operating activities | 7,577 | 9,899 | 72,219 | 48,033 |
| Settlement of decommissioning obligations | 639 | 541 | 1,526 | 2,177 |
| Changes in non-cash working capital | (9,638) | 7,281 | (2,322) | 45,858 |
| **Funds flow from operations** | **(1,422)** | **17,721** | **71,423** | **96,063** |