# Q3 REPORT
2022

TSX BTE

## BAYTEX ANNOUNCES THIRD QUARTER 2022 RESULTS AND CONTINUED STRONG CLEARWATER DRILLING RESULTS

CALGARY, ALBERTA (November 3, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and nine months ended September 30, 2022 (all amounts are in Canadian dollars unless otherwise noted).

"We continue to deliver on our commitments with a much-improved balance sheet (0.9x net debt to trailing 12 month EBITDA ratio), substantial free cash flow generation ($478 million through nine months) and a shareholder return framework that is driving real value for our shareholders (3.8% of shares repurchased to-date). We are building operational momentum as we approach 2023 with current Clearwater production of 10,000 bbl/d driving an expected corporate exit rate production of 87,000 to 88,000 boe/d. Our first four Clearwater wells this quarter generated 30 day initial production rates of 1,100 bbl/d per well and we have initiated down-spacing (moving to 5 wells per section) which offers a potential 20% increase in our future Peavine Clearwater drilling inventory," commented Ed LaFehr, President and Chief Executive Officer.

### Highlights

- Generated production of 83,194 boe/d (84% oil and NGL) in Q3/2022, a 4% increase over Q3/2021. Production in October increased to over 87,000 boe/d.
- Delivered adjusted funds flow(1) of $284 million ($0.51 per basic share) in Q3/2022, a 43% increase compared to $198 million ($0.35 per basic share) in Q3/2021.
- Generated free cash flow(2) of $112 million ($0.20 per basic share) in Q3/2022, an 11% increase compared to $101 million ($0.18 per basic share) in Q3/2021.
- Reported cash flows from operating activities of $310 million ($0.56 per basic share) in Q3/2022, a 73% increase compared to $179 million ($0.32 per basic share) in Q3/2021.
- Reduced net debt(1) by 21% to $1.1 billion, from $1.4 billion at year-end 2021.
- Repurchased 21.6 million common shares year-to-date, representing 3.8% of our shares outstanding, at an average price of $6.53 per share.
- Divested of non-core natural gas assets in west central Alberta for net proceeds of $26 million. Production associated with the divestiture was approximately 600 boe/d.
- Generated production from our Clearwater play at Peavine of 8,191 bbl/d in Q3/2022. Production during the month of October averaged 10,000 bbl/d from 24 producing wells.

### CEO Transition

As previously announced, the Board of Directors appointed Mr. Eric Greager to the position of President and Chief Executive Officer and as a Director effective November 4, 2022. Mr. Greager succeeds Mr. LaFehr who announced his intention to retire earlier this year. In keeping with this transition, Mr. LaFehr has also stepped down from the Board of Directors, he will remain in an advisory capacity until January 2023.

### 2022 Outlook

We remain intensely focused on maintaining capital discipline and driving meaningful free cash flow in our business. We continue to execute our 2022 plan and anticipate full-year production of approximately 84,000 boe/d (mid-point of previous guidance range of 83,000 to 85,000 boe/d) with a targeted exit rate of 87,000 to 88,000 boe/d. Based on the forward strip for the balance of 2022(3) we expect to generate approximately $650 million of free cash flow this year.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Q4/2022 pricing assumptions: WTI - US$86/bbl; WCS differential - US$26/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$6.60/mcf; AECO Gas - $5.25/mcf and Exchange Rate (CAD/USD) - 1.36.

## 2022 Outlook (continued)

We now anticipate full-year 2022 exploration and development expenditures of approximately $515 million, up 3% from our previously targeted $500 million (representing the high end of our prior guidance range of $450 to $500 million). The incremental capital largely reflects the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. operations and further level loading of activity through year-end to maintain the efficiency of our operations.

We have increased our general and administrative expense by 12% largely to reflect the impacts of inflation and expanded staffing costs associated with our higher pace of activity and strong performance. We have also fine-tuned our interest expense guidance to reflect higher interest rates on our credit facilities and the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

The following table highlights our 2022 annual guidance.

| | **2022 Guidance (1)** | **2022 Revised Guidance** |
|---|---:|---:|
| Exploration and development expenditures | $450 - $500 million | ~ $515 million |
| Production (boe/d) | 83,000 - 85,000 | ~ 84,000 boe/d |
| | | |
| Expenses: | | |
| Average royalty rate (2) | 21.0% - 22.0% | no change |
| Operating (3) | $13.75 - $14.25/boe | no change |
| Transportation (3) | $1.50 - $1.60/boe | no change |
| General and administrative (3) | $43 million ($1.40/boe) | $48 million ($1.57/boe) |
| Interest (3) | $75 million ($2.45/boe) | $79 million ($2.58/boe) |
| | | |
| Leasing expenditures | $3 million | no change |
| Asset retirement obligations | $20 million | no change |

Our 2023 capital budget is expected to be released in early December following approval by our Board of Directors.

## Shareholder Returns

Our improved financial position enabled us to implement the second phase of our enhanced shareholder return framework in May, allocating 25% of annual free cash flow to a share buyback program with 75% of free cash flow allocated to debt reduction.

During the third quarter, we repurchased 12.6 million common shares for $79 million, representing 2.2% of our shares outstanding, at an average price of $6.25 per share. Year-to-date, we have repurchased 21.6 million common shares for $141 million, representing 3.8% of our shares outstanding, at an average price of $6.53 per share.

As of September 30, 2022, our net debt(4) totaled $1.1 billion, representing a net debt to EBITDA(5) ratio (trailing twelve months) of 0.9x. Our net debt at quarter-end was largely unchanged from Q2/2022 due to our share buyback program and the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt. Based on current commodity prices and forecast free cash flow for the fourth quarter, we expect to exit 2022 with net debt of under $1.0 billion. In addition, we expect to reach a net debt level of $800 million by mid-2023(6), at which time, we anticipate increasing direct shareholder returns to 50% of our free cash flow and accelerating our share buyback program.

We have also established an ultimate net debt target for the company of $400 million, which represents an expected net debt to EBITDA ratio of 1.0x at a US$45 WTI price. We feel this level of net debt will provide us with full flexibility to run our business through the commodity price cycles and generate meaningful returns for our shareholders. At current commodity prices, we expect to achieve this net debt level in 2024, at which point we intend to increase direct shareholder returns to 75% of our free cash flow.

(1) As announced on July 27, 2022.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures in this press release for further information.
(5) Calculated in accordance with the Credit Facilities Agreement.
(6) 2023 pricing assumptions: WTI - US$79/bbl; WCS differential - US$23/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$5.20/mcf; AECO Gas - $4.65/mcf and Exchange Rate (CAD/USD) - 1.36.

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **September 30, 2022** | June 30, 2022 | September 30, 2021 | **September 30, 2022** | September 30, 2021 |
| **FINANCIAL** (thousands of Canadian dollars, except per common share amounts) | | | | | |
| **Petroleum and natural gas sales** | **$ 712,065** | $ 854,169 | $ 488,736 | **$ 2,240,059** | $ 1,315,792 |
| **Adjusted funds flow** (1) | **284,288** | 345,704 | 198,397 | **909,599** | 530,862 |
| Per share – basic | **0.51** | 0.61 | 0.35 | **1.62** | 0.94 |
| Per share – diluted | **0.51** | 0.60 | 0.35 | **1.60** | 0.93 |
| **Free cash flow** (2) | **111,568** | 245,316 | 101,215 | **478,202** | 284,196 |
| Per share – basic | **0.20** | 0.43 | 0.18 | **0.85** | 0.50 |
| Per share – diluted | **0.20** | 0.43 | 0.18 | **0.84** | 0.50 |
| **Cash flows from operating activities** | **310,423** | 360,034 | 178,961 | **869,431** | 471,817 |
| Per share – basic | **0.56** | 0.63 | 0.32 | **1.55** | 0.84 |
| Per share – diluted | **0.56** | 0.63 | 0.31 | **1.53** | 0.83 |
| **Net income** | **264,968** | 180,972 | 32,713 | **502,798** | 1,050,361 |
| Per share – basic | **0.48** | 0.32 | 0.06 | **0.89** | 1.86 |
| Per share – diluted | **0.47** | 0.32 | 0.06 | **0.89** | 1.84 |
| **Capital Expenditures** | | | | | |
| Exploration and development expenditures | **$ 167,453** | $ 96,633 | $ 94,235 | **$ 417,908** | $ 239,308 |
| Acquisitions and divestitures | **(25,460)** | 194 | (612) | **(25,234)** | (833) |
| Total oil and natural gas capital expenditures | **$ 141,993** | $ 96,827 | $ 93,623 | **$ 392,674** | $ 238,475 |
| **Net Debt** | | | | | |
| Credit facilities | **$ 450,051** | $ 496,917 | $ 546,803 | **$ 450,051** | $ 546,803 |
| Long-term notes | **648,207** | 643,600 | 1,000,171 | **648,207** | 1,000,171 |
| Long-term debt | **1,098,258** | 1,140,517 | 1,546,974 | **1,098,258** | 1,546,974 |
| Working capital | **15,301** | (17,220) | 17,684 | **15,301** | 17,684 |
| Net debt (1) | **$ 1,113,559** | $ 1,123,297 | $ 1,564,658 | **$ 1,113,559** | $ 1,564,658 |
| **Shares Outstanding - basic** (thousands) | | | | | |
| Weighted average | **553,409** | 566,997 | 564,211 | **561,931** | 563,492 |
| End of period | **547,615** | 560,139 | 564,213 | **547,615** | 564,213 |
| **BENCHMARK PRICES** | | | | | |
| **Crude oil** | | | | | |
| WTI (US$/bbl) | **$ 91.56** | $ 108.41 | $ 70.56 | **$ 98.09** | $ 64.82 |
| MEH oil (US$/bbl) | **96.15** | 112.41 | 71.64 | **101.76** | 66.05 |
| MEH oil differential to WTI (US$/bbl) | **4.59** | 4.00 | 1.08 | **3.67** | 1.23 |
| Edmonton par ($/bbl) | **116.79** | 137.79 | 83.78 | **123.41** | 75.88 |
| Edmonton par differential to WTI (US$/bbl) | **(2.13)** | (0.47) | (4.07) | **(1.89)** | (4.19) |
| WCS heavy oil ($/bbl) | **93.62** | 122.05 | 71.81 | **105.65** | 65.47 |
| WCS differential to WTI (US$/bbl) | **(19.87)** | (12.80) | (13.57) | **(15.74)** | (12.51) |
| **Natural gas** | | | | | |
| NYMEX (US$/mmbtu) | **$ 8.20** | $ 7.17 | $ 4.01 | **$ 6.77** | $ 3.18 |
| AECO ($/mcf) | **5.81** | 6.27 | 3.54 | **5.56** | 3.11 |
| **CAD/USD average exchange rate** | **1.3059** | 1.2766 | 1.2601 | **1.2829** | 1.2515 |

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **September 30, 2022** | June 30, 2022 | September 30, 2021 | **September 30, 2022** | September 30, 2021 |
| **OPERATING** | | | | | |
| **Daily Production** | | | | | |
| Light oil and condensate (bbl/d) | **33,247** | 33,007 | 35,614 | **33,437** | 36,060 |
| Heavy oil (bbl/d) | **29,244** | 28,586 | 21,996 | **27,703** | 21,752 |
| NGL (bbl/d) | **7,536** | 7,468 | 7,174 | **7,547** | 6,995 |
| Total liquids (bbl/d) | **70,027** | 69,061 | 64,784 | **68,686** | 64,807 |
| Natural gas (mcf/d) | **79,003** | 84,169 | 90,528 | **82,232** | 90,812 |
| Oil equivalent (boe/d @ 6:1) (3) | **83,194** | 83,090 | 79,872 | **82,392** | 79,942 |
| | | | | | |
| **Netback** (thousands of Canadian dollars) | | | | | |
| Total sales, net of blending and other expense (2) | **$ 671,120** | $ 797,274 | $ 469,155 | **$ 2,100,779** | $ 1,259,124 |
| Royalties | **(146,994)** | (171,559) | (90,523) | **(441,273)** | (239,004) |
| Operating expense | **(110,139)** | (107,426) | (84,196) | **(318,331)** | (247,645) |
| Transportation expense | **(12,771)** | (11,758) | (7,818) | **(33,744)** | (24,092) |
| Operating netback (2) | **$ 401,216** | **$ 506,531** | **$ 286,618** | **$ 1,307,431** | **$ 748,383** |
| General and administrative | **(12,003)** | (11,640) | (9,980) | **(35,325)** | (29,323) |
| Cash financing and interest | **(19,774)** | (20,474) | (22,793) | **(60,675)** | (70,750) |
| Realized financial derivatives loss | **(76,408)** | (124,042) | (53,905) | **(284,816)** | (113,697) |
| Other (4) | **(8,743)** | (4,671) | (1,543) | **(17,016)** | (3,751) |
| Adjusted funds flow (1) | **$ 284,288** | **$ 345,704** | **$ 198,397** | **$ 909,599** | **$ 530,862** |
| | | | | | |
| **Netback** (per boe) (5) | | | | | |
| Total sales, net of blending and other expense (2) | **$ 87.68** | $ 105.44 | $ 63.85 | **$ 93.40** | $ 57.69 |
| Royalties | **(19.21)** | (22.69) | (12.32) | **(19.62)** | (10.95) |
| Operating expense | **(14.39)** | (14.21) | (11.46) | **(14.15)** | (11.35) |
| Transportation expense | **(1.67)** | (1.56) | (1.06) | **(1.50)** | (1.10) |
| Operating netback (2) | **$ 52.41** | **$ 66.98** | **$ 39.01** | **$ 58.13** | **$ 34.29** |
| General and administrative | **(1.57)** | (1.54) | (1.36) | **(1.57)** | (1.34) |
| Cash financing and interest | **(2.58)** | (2.71) | (3.10) | **(2.70)** | (3.24) |
| Realized financial derivatives loss | **(9.98)** | (16.41) | (7.34) | **(12.66)** | (5.21) |
| Other (4) | **(1.14)** | (0.60) | (0.21) | **(0.76)** | (0.18) |
| Adjusted funds flow (1) | **$ 37.14** | **$ 45.72** | **$ 27.00** | **$ 40.44** | **$ 24.32** |

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q3/2022 MD&A for further information on these amounts.
(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest expense or realized financial derivatives loss divided by barrels of oil equivalent production volume for the applicable period.

**Q3/2022 Results**

During the third quarter, we delivered strong operating and financial results which has set the stage for continued momentum as we approach 2023. In addition, we advanced our exciting Clearwater play at Peavine with initial results from our H2/2022 drilling program delivering among the best wells drilled to date in the play.

Production during the third quarter averaged 83,194 boe/d (84% oil and NGL) as compared to 83,090 boe/d (83% oil and NGL) in Q2/2022. Production in October increased to over 87,000 boe/d, in line with our targeted exit production rate of 87,000 to 88,000 boe/d. Exploration and development expenditures totaled $167 million in Q3/2022 and we participated in the drilling of 86 (72.0 net) wells.

During the quarter, we delivered adjusted funds flow[(1)] of $284 million ($0.51 per basic share) and net income of $265 million ($0.48 per basic share). We generated free cash flow[(2)] of $112 million ($0.20 per basic share) which brings our year-to-date free cash flow to $478 million ($0.85 per basic share).

**Operating Results**

*Eagle Ford and Viking Light Oil*

Production in the Eagle Ford averaged 27,391 boe/d (82% oil and NGL) during Q3/2022 and generated an operating netback[(2)] of $140 million. We invested $50 million on exploration and development in the Eagle Ford during the quarter and brought 19 (4.1 net) wells onstream. We expect to bring approximately 18 net wells onstream in 2022.

Production in the Viking averaged 16,019 boe/d (88% oil and NGL) during Q3/2022 and generated an operating netback of $116 million. We invested $62 million on exploration and development in the Viking during the quarter and brought 42 (40.5 net) wells onstream. We expect to bring approximately 130 net wells onstream in 2022.

*Heavy Oil*

Our heavy oil assets at Peace River and Lloydminster (excluding Clearwater development) produced a combined 23,377 boe/d (90% oil and NGL) during Q3/2022 and generated an operating netback of $80 million. We invested $31 million on exploration and development during the quarter and brought onstream 2 net Bluesky wells at Peace River and 2.6 net wells at Lloydminster. In 2022, we will drill approximately 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster.

*Peace River Clearwater*

Production in the Clearwater averaged 8,191 boe/d (100% oil) during Q3/2022 and generated an operating netback of $37 million. Production during the month of October averaged approximately 10,000 bbl/d from 24 producing wells.

Our second half drilling program kicked off in July and will include the drilling of 13 Clearwater wells, including 12 wells at Peavine and one well at Seal that follows up a successful exploration well from 2021. The first four wells from the H2/2022 drilling program generated average 30-day initial production rates of 1,100 bbl/d per well. Initial well performance continues to outperform type curve assumptions and we now hold 13 of the top 15 initial rate wells drilled across the play.

We continue to optimize planned development for our Peavine lands, which now includes a combination of traditional multi-lateral wells (eight one-mile long laterals) and extended reach horizontal ("ERH") multi-lateral wells (four two-mile long laterals). The ERH multi-lateral wells are utilized to provide appropriate set-backs to residents and environmentally sensitive areas and were among the first of their type to be drilled in western Canada.

Following further detailed reservoir and economic analysis of the Peavine Clearwater, our most recent wells were drilled at 40 metre inter-lateral spacing (5 wells per section) whereas our initial wells were drilled at 50 metre inter-lateral spacing (4 wells per section). At this tighter spacing, we could potentially see a 20% increase in our prospective drilling inventory yielding meaningfully improved resource recovery and value.

The Clearwater generates among the strongest economics within our portfolio with payouts of less than five months at US$80 WTI and has the ability to grow organically while enhancing our free cash flow profile. To-date, we have de-risked 50 sections (of our 80-section Peavine land base) and believe the lands hold the potential for greater than 250 locations with production increasing to approximately 15,000 bbl/d. When combined with our legacy acreage position in northwest Alberta, we estimate that over 125 sections of our lands are highly prospective for Clearwater development.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.

*Pembina Area Duvernay Light Oil*

Production in the Pembina Duvernay averaged 3,405 boe/d (84% oil and NGL) during Q3/2022.

The Pembina Duvernay shale is an early stage, high operating netback light oil resource play. During the first quarter, we drilled a three-well pad on the northern edge of our land base that was brought on production in June/July. Performance of the three-wells has tracked to type well forecast for that region, generating an average 90-day initial production rate of approximately 700 boe/d per well (86% crude oil and NGL). The three wells, each drilled to a vertical depth of 2,400 metres with a horizontal lateral of 1.85 miles, were drilled and completed for $8.3 million per well.

As we progress our understanding of the reservoir and gain confidence in capital execution and well performance, we believe the Pembina Duvernay shale has the potential to generate competitive returns within our portfolio, with payouts of 13 to 15 months at US$80 WTI. For 2023, we are in the planning stages of a four-well program to further progress our development. Across our Pembina acreage, we hold 200 sections of contiguous 100% working interest lands.

**Financial Liquidity**

Our net debt[1], which includes our credit facilities, long-term notes and working capital, totaled $1.11 billion at September 30, 2022, down from $1.41 billion at December 31, 2021.

During the third quarter, we repurchased and cancelled US$26.8 million principal amount of 8.75% long-term notes due 2027.

As of September 30, 2022, we had $714 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $699 million.

**Risk Management**

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow.

For the fourth quarter of 2022, we have hedges on approximately 40% of our net crude oil exposure utilizing a combination of a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl and swaptions at US$53.50/bbl. We also have WTI-MSW differential hedges on approximately 50% of our expected net Canadian light oil exposure at US$3.73/bbl and WCS differential hedges on approximately 60% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.28/bbl.

For 2023, we have entered into hedges on approximately 18% of our net crude oil exposure utilizing a 3-way option structure that provides price protection at US$78.36/bbl with upside participation to US$96.11/bbl

A complete listing of our financial derivative contracts can be found in Note 16 to our Q3/2022 financial statements.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

**Additional Information**

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2022 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

**Conference Call Tomorrow**
**9:00 a.m. MDT (11:00 a.m. EDT)**

Baytex will host a conference call tomorrow, November 4, 2022, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter https://services.choruscall.ca/links/baytex20221104.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

**Advisory Regarding Forward-Looking Statements**

*In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.*

*Specifically, this press release contains forward-looking statements relating to but not limited to: our expected exit rate production of 87,000 to 88,000 boe/d; the potential for a 20% increase in future Clearwater drilling inventory as a result of down-spacing to 5 wells per section; we are focused on maintaining capital discipline and driving meaningful free cash flow; that we expect to generate $650 million of free cash flow in 2022; our revised guidance for 2022 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; that our 2023 capital budget is expected to be released in early December; that we will continue allocating 25% of free cash flow to a share buyback program and 75% to debt reduction; that we expect our net debt will be under $1 billion at year-end 2022 and that our net debt will be $800 million by mid-2023 at which point we will increase direct shareholder returns to 50% of free cash flow and accelerate our share buyback program; our expected 1.0x net debt to EBITDA ratio at a US$45 WTI price when we reach our $400 million net debt target, which we expect to reach in 2024 at which point we will consider steps to further enhance shareholder returns; in 2022 that we expect to: bring on production 18 net wells in the Eagle Ford and 130 in the Viking; that we expect to drill 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster in 2022; we plan to drill 13 additional Clearwater wells in H2/2022; that we could see a 20% increase in our prospective drilling inventory in the Clearwater due to down spacing which could yield meaningfully improved resource recovery and value; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than five months at US $80 WTI and has the ability to grow organically while enhancing our free cash flow profile; to date we have de-risked 50 sections of Peavine lands which hold the potential for 250 locations, with production increasing to 15,000 bbl/d; we have over 125 sections that are highly prospective for Clearwater development; that we believe the Pembina Duvernay shale has the potential to generate competitive returns within our portfolio, with payouts of 13 to 15 months at US$80 WTI and for 2023, we are in the planning stages of a four-well program to further progress our development; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the WTI-MSW differential and WCS differential that we have hedged for 2022 and the percentage of our net exposure to crude oil that we have hedged for 2023.*

*These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.*

*Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.*

*These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.*

*The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.*

*There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.*

**Specified Financial Measures**

*In this press release, we refer to certain financial measures (such as free cash flow, operating netback, average royalty rate and total sales, net of blending and other expense) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers. In addition, this press release contains the terms "adjusted funds flow" and "net debt" which are considered capital management measures.*

**Non-GAAP Financial Measures**

Total sales, net of blending and other expense

*Total sales, net of blending and other expense is not a measurement based on GAAP in Canada and represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.*

Operating netback

*Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.*

*The following table reconciles total sales, net of blending and other expense and operating netback to petroleum and natural gas sales.*

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | **2022** | 2021 |
| Petroleum and natural gas sales | **$ 712,065** | $ 488,736 | **$ 2,240,059** | $ 1,315,792 |
| Blending and other expense | **(40,945)** | (19,581) | **(139,280)** | (56,668) |
| Total sales, net of blending and other expense | **671,120** | 469,155 | **2,100,779** | 1,259,124 |
| Royalties | **(146,994)** | (90,523) | **(441,273)** | (239,004) |
| Operating expense | **(110,139)** | (84,196) | **(318,331)** | (247,645) |
| Transportation expense | **(12,771)** | (7,818) | **(33,744)** | (24,092) |
| Operating netback | **$ 401,216** | $ 286,618 | **$ 1,307,431** | $ 748,383 |

Free cash flow

*Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.*

*Free cash flow is reconciled to cash flows from operating activities in the following table.*

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | **2022** | 2021 |
| Cash flows from operating activities | **$ 310,423** | $ 178,961 | **$ 869,431** | $ 471,817 |
| Change in non-cash working capital | **(30,734)** | 17,631 | **29,560** | 54,830 |
| Additions to exploration and evaluation assets | **—** | (89) | **(5,897)** | (733) |
| Additions to oil and gas properties | **(167,453)** | (94,146) | **(412,011)** | (238,575) |
| Payments on lease obligations | **(668)** | (1,142) | **(2,881)** | (3,143) |
| Free cash flow | **$ 111,568** | $ 101,215 | **$ 478,202** | $ 284,196 |

**Non-GAAP Financial Ratios**

Total sales, net of blending and other expense per boe

*Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense divided by barrels of oil equivalent production volume for the applicable period.*

Average royalty rate

*Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.*

Operating netback per boe

*Operating netback per boe is equal to operating netback divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.*

**Capital Management Measures**

Net debt

*We define net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash and trade and other receivables. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.*

*The following table summarizes our calculation of net debt.*

| *($ thousands)* | **September 30, 2022** | December 31, 2021 |
|---|---|---|
| Credit facilities | **$ 447,475** | $ 505,171 |
| Unamortized debt issuance costs - Credit facilities (1) | **2,576** | 1,343 |
| Long-term notes | **639,679** | 874,527 |
| Unamortized debt issuance costs - Long-term notes (1) | **8,528** | 11,393 |
| Trade and other payables | **271,400** | 190,692 |
| Cash | **(4,410)** | — |
| Trade and other receivables | **(251,689)** | (173,409) |
| Net debt | **$ 1,113,559** | $ 1,409,717 |

(1) *Unamortized debt issuance costs were obtained from Note 6 - Credit Facilities and Note 7 - Long-term Notes from the consolidated financial statements for the three and nine months ended September 30, 2022.*

Adjusted funds flow

*Adjusted funds flow is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.*

*Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.*

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | **2022** | 2021 |
| Cash flow from operating activities | **$ 310,423** | $ 178,961 | **$ 869,431** | $ 471,817 |
| Change in non-cash working capital | **(30,734)** | 17,631 | **29,560** | 54,830 |
| Asset retirement obligations settled | **4,599** | 1,805 | **10,608** | 4,215 |
| Adjusted funds flow | **$ 284,288** | $ 198,397 | **$ 909,599** | $ 530,862 |

**Advisory Regarding Oil and Gas Information**

*Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

*References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.*

*Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 2022. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas. All production from our Peavine asset is 100% Heavy Oil.*

| | Three Months Ended September 30, 2022 | | | | | Nine Months Ended September 30, 2022 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Heavy Oil (bbl/d) | Light and Medium Oil (bbl/d) | NGL (bbl/d) | Natural Gas (Mcf/d) | Oil Equivalent (boe/d) | Heavy Oil (bbl/d) | Light and Medium Oil (bbl/d) | NGL (bbl/d) | Natural Gas (Mcf/d) | Oil Equivalent (boe/d) |
| **Canada – Heavy** | | | | | | | | | | |
| Peace River | 10,282 | 13 | 41 | 12,026 | 12,340 | 10,691 | 9 | 33 | 11,877 | 12,713 |
| Lloydminster | 10,770 | 4 | — | 1,575 | 11,037 | 10,773 | 9 | — | 1,696 | 11,065 |
| Peavine | 8,191 | — | — | — | 8,191 | 6,240 | — | — | — | 6,240 |
| **Canada - Light** | | | | | | | | | | |
| Viking | — | 13,908 | 191 | 11,516 | 16,019 | — | 14,562 | 188 | 12,203 | 16,783 |
| Duvernay | — | 1,894 | 959 | 3,305 | 3,405 | — | 1,233 | 790 | 2,555 | 2,449 |
| Remaining Properties | — | 690 | 682 | 20,638 | 4,811 | — | 769 | 864 | 22,972 | 5,461 |
| **United States** | | | | | | | | | | |
| Eagle Ford | — | 16,738 | 5,663 | 29,943 | 27,391 | — | 16,855 | 5,671 | 30,929 | 27,681 |
| **Total** | 29,244 | 33,247 | 7,536 | 79,003 | 83,194 | 27,703 | 33,437 | 7,546 | 82,232 | 82,392 |

*This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. Of the 250 or more potential drilling locations currently identified in the Clearwater, as at December 31, 2021, 4 are proved locations, 5 are probable locations and the remainder are unbooked locations.*

## Baytex Energy Corp.

Baytex Energy Corp. is an energy company based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Baytex's common shares trade on the Toronto Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

**Brian Ector, Vice President, Capital Markets**

Toll Free Number: 1-800-524-5521
Email: investor@baytexenergy.com

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2022. This information is provided as of November 3, 2022. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and nine months ended September 30, 2022 ("Q3/2022" and "YTD 2022") have been compared with the results for the three and nine months ended September 30, 2021 ("Q3/2021" and "YTD 2021"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2022, its audited comparative consolidated financial statements for the years ended December 31, 2021 and 2020, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2021. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

## BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused energy company based in Calgary, Alberta. The Company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

## THIRD QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results in Q3/2022. Energy prices remained strong due to uncertainty surrounding global energy security while recent concerns over high inflation and slowing economic activity have caused recent declines in oil prices. As a result, the average WTI benchmark price for Q3/2022 was US$91.56/bbl which was US$21.00/bbl higher than Q3/2021 when WTI averaged US$70.56/bbl. Strong benchmark prices contributed to adjusted funds flow[(1)] of $284.3 million and free cash flow[(2)] of $111.6 million. Production increased to 83,194 boe/d in Q3/2022 compared to 79,872 boe/d in Q3/2021 primarily from strong well results in our Clearwater program. Production was consistent with our expectations and within our annual guidance range of 83,000 - 85,000 boe/d.

Exploration and development expenditures were $167.5 million for Q3/2022 with $117.2 million invested in Canada and $50.3 million in the U.S. In Canada, we brought 11 (8.6 net) heavy oil wells and 45 (43.5 net) light oil wells on production during Q3/2022. In the U.S., we brought 19 (4.1 net) wells on production during Q3/2022. Production in Canada was 55,803 boe/d in Q3/2022, a 7,679 boe/d increase from Q3/2021, driven primarily from our success in the Clearwater play at Peavine. In the U.S. production decreased to 27,391 boe/d in Q3/2022 from 31,748 boe/d in Q3/2021 with less activity on our lands in 2022.

Adjusted funds flow of $284.3 million and free cash flow of $111.6 million in Q3/2022 were higher than $198.4 million and $101.2 million for Q3/2021, respectively, as a result of higher benchmark prices and production. Our strong operating and financial results contributed to net income of $265.0 million for Q3/2022 compared to net income of $32.7 million in Q3/2021.

*(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

We used free cash flow generated during Q3/2022 for debt reduction and to continue our shareholder returns. We repurchased and cancelled 12.6 million common shares for $78.8 million during the quarter, for a total of 21.6 million shares for $141.3 million repurchased as of Q3/2022, representing 3.8% of the shares outstanding at commencement of the normal course issuer bid.

Net debt[1] was $1.11 billion at September 30, 2022 compared to $1.12 billion at Q2/2022 and $1.41 billion at Q4/2021. The reduction from Q4/2021 reflects YTD 2022 free cash flow[2] of $478.2 million along with $25.5 million of disposition proceeds offset by $141.3 million of share repurchases and a $63.9 million increase in the reported amount of our U.S. dollar denominated net debt due to the weakening of the Canadian dollar relative to the U.S. dollar during YTD 2022.

*(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

**2022 GUIDANCE**

We now anticipate 2022 exploration and development expenditures of approximately $515 million which is up from our previously targeted $500 million (representing the high end of our prior guidance range of $450 to $500 million). The incremental capital largely reflects the impact of a strengthening U.S. dollar relative to the Canadian dollar, on our U.S. operations and further level loading of activity through year-end to maintain the efficiency of our operations.

We have increased our general and administrative expense by 12% to reflect the impacts of inflation and expanded staffing levels associated with our higher pace of activity along with anticipated performance based pay reflecting our strong financial performance to date. We have also updated our interest expense guidance to reflect higher interest rates on our credit facilities and the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

The following table highlights our 2022 annual guidance.

| | Previous Annual Guidance [1] | Revised Annual Guidance |
|---|---|---|
| Exploration and development expenditures | $450 - $500 million | ~ $515 million |
| Production (boe/d) | 83,000 - 85,000 | ~ 84,000 boe/d |
| Expenses: | | |
| Average royalty rate [2] | 21.0% - 22.0% | no change |
| Operating [3] | $13.75 - $14.25/boe | no change |
| Transportation [3] | $1.50 - $1.60/boe | no change |
| General and administrative [3] | $43 million ($1.40/boe) | $48 million ($1.57/boe) |
| Interest [3] | $75 million ($2.45/boe) | $79 million ($2.58/boe) |
| Leasing expenditures | $3 million | no change |
| Asset retirement obligations | $20 million | no change |

*(1) As announced on July 27, 2022.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(3) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.*

## RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

### Production

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| **Daily Production** | | | | | | |
| Liquids (bbl/d) | | | | | | |
| Light oil and condensate | **16,509** | **16,738** | **33,247** | 16,532 | 19,082 | 35,614 |
| Heavy oil | **29,244** | **—** | **29,244** | 21,996 | — | 21,996 |
| Natural Gas Liquids (NGL) | **1,873** | **5,663** | **7,536** | 1,230 | 5,944 | 7,174 |
| Total liquids (bbl/d) | **47,626** | **22,401** | **70,027** | 39,758 | 25,026 | 64,784 |
| Natural gas (mcf/d) | **49,060** | **29,943** | **79,003** | 50,197 | 40,331 | 90,528 |
| Total production (boe/d) | **55,803** | **27,391** | **83,194** | 48,124 | 31,748 | 79,872 |
| **Production Mix** | | | | | | |
| Segment as a percent of total | **67 %** | **33 %** | **100 %** | 60 % | 40 % | 100 % |
| Light oil and condensate | **30 %** | **61 %** | **40 %** | 34 % | 60 % | 45 % |
| Heavy oil | **52 %** | **— %** | **35 %** | 46 % | — % | 28 % |
| NGL | **3 %** | **21 %** | **9 %** | 3 % | 19 % | 9 % |
| Natural gas | **15 %** | **18 %** | **16 %** | 17 % | 21 % | 18 % |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| **Daily Production** | | | | | | |
| Liquids (bbl/d) | | | | | | |
| Light oil and condensate | **16,582** | **16,855** | **33,437** | 17,130 | 18,930 | 36,060 |
| Heavy oil | **27,703** | **—** | **27,703** | 21,752 | — | 21,752 |
| Natural Gas Liquids (NGL) | **1,875** | **5,671** | **7,546** | 1,657 | 5,338 | 6,995 |
| Total liquids (bbl/d) | **46,160** | **22,526** | **68,686** | 40,539 | 24,268 | 64,807 |
| Natural gas (mcf/d) | **51,303** | **30,929** | **82,232** | 51,416 | 39,396 | 90,812 |
| Total production (boe/d) | **54,711** | **27,681** | **82,392** | 49,108 | 30,834 | 79,942 |
| **Production Mix** | | | | | | |
| Segment as a percent of total | **66 %** | **34 %** | **100 %** | 61 % | 39 % | 100 % |
| Light oil and condensate | **30 %** | **61 %** | **41 %** | 35 % | 61 % | 45 % |
| Heavy oil | **51 %** | **— %** | **34 %** | 44 % | — % | 27 % |
| NGL | **3 %** | **20 %** | **9 %** | 3 % | 17 % | 9 % |
| Natural gas | **16 %** | **19 %** | **16 %** | 18 % | 22 % | 19 % |

Production was 83,194 boe/d for Q3/2022 and 82,392 boe/d for YTD 2022 compared to 79,872 boe/d for Q3/2021 and 79,942 boe/d for YTD 2021. Total production was higher in Q3/2022 and YTD 2022 compared to comparable periods of 2021 due to our successful development program in Canada which includes strong well results from our Clearwater development program.

In Canada, production was 55,803 boe/d for Q3/2022 and 54,711 boe/d for YTD 2022 compared to 48,124 boe/d for Q3/2021 and 49,108 boe/d for YTD 2021. Our successful 2022 development program and strong well performance from our Clearwater development program has resulted in production that was 7,679 boe/d higher in Q3/2022 and 5,603 boe/d higher YTD 2022 relative to the comparative periods of 2021.

In the U.S., production was 27,391 boe/d for Q3/2022 and 27,681 boe/d for YTD 2022 compared to 31,748 boe/d for Q3/2021 and 30,834 boe/d for YTD 2021. U.S. production was lower in 2022 due to reduced activity levels during the second half of 2021 and YTD 2022. We initiated production from 56 (12.7 net) wells during YTD 2022 compared to 79 (20.6 net) wells during the comparative period in 2021.

Total production of 82,392 boe/d for YTD 2022 is consistent with expectations and is slightly below our annual guidance of approximately 84,000 boe/d for 2022 as we are targeting an exit rate of 87,000 - 88,000 boe/d for Q4/2022.

**COMMODITY PRICES**

The prices received for our crude oil and natural gas production directly impact our earnings, free cash flow and our financial position.

**Crude Oil**

Global benchmark pricing for crude oil decreased during Q3/2022 due to the release of barrels from the U.S. Strategic Petroleum Reserve which increased supply along with concerns over slowing economic activity and reduced future demand. Despite these recent declines, crude oil prices remained higher relative to 2021 due to strong demand and heightened concern over supply caused by the conflict in Ukraine. The WTI price averaged US$91.56/bbl for Q3/2022 and US$98.09/bbl for YTD 2022 compared to Q3/2021 and YTD 2021 when WTI averaged US$70.56/bbl and US$64.82/bbl, respectively.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$96.15/bbl during Q3/2022 and US$101.76/bbl during YTD 2022 which is higher than US$71.64/bbl during Q3/2021 and US$66.05/bbl during YTD 2021. The MEH benchmark trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$4.59/bbl and US$3.67/bbl for Q3/2022 and YTD 2022 compared to premiums of US$1.08/bbl and US$1.23/bbl for Q3/2021 and YTD 2021, respectively. The MEH benchmark traded at a higher premium to WTI in both periods of 2022 as a result of heightened uncertainty over global supply relative to 2021.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $116.79/bbl during Q3/2022 and $123.41/bbl during YTD 2022 compared to $83.78/bbl during Q3/2021 and $75.88/bbl during YTD 2021. Edmonton par traded at a discount to WTI of US$2.13/bbl for Q3/2022 and US$1.89/bbl for YTD 2022 which is slightly narrower compared to a discount of US$4.07/bbl for Q3/2021 and US$4.19/bbl for YTD 2021 due to higher demand for Canadian light oil in 2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS heavy oil price for Q3/2022 and YTD 2022 averaged $93.62/bbl and $105.65/bbl, respectively, compared to $71.81/bbl and $65.47/bbl for the same periods of 2021. The WCS heavy oil differential was US$19.87/bbl in Q3/2022 and US$15.74/bbl in YTD 2022 which is wider than US$13.57/bbl for Q3/2021 and US$12.51/bbl for YTD 2021 due to reduced refining capacity for Canadian heavy oil following the release of oil from the U.S. Strategic Petroleum Reserve and refining outages.

**Natural Gas**

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. Strong global demand to replace Russian supply of natural gas resulted in higher NYMEX benchmark prices in 2022 relative to 2021.The NYMEX natural gas benchmark averaged US$8.20/mmbtu for Q3/2022 and US$6.77/mmbtu for YTD 2022 compared to US$4.01/mmbtu for Q3/2021 and US$3.18/mmbtu for YTD 2021.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. Increased global demand for natural gas resulted in higher AECO benchmark prices in 2022 relative to 2021 while maintenance on the Nova Gas Transmission Line limited export capacity from Alberta and resulted in a wider AECO basis to NYMEX in 2022 relative to 2021. The AECO benchmark averaged $5.81/mcf during Q3/2022 and $5.56/mcf during YTD 2022 which is higher than $3.54/mcf for Q3/2021 and $3.11/mcf for YTD 2021.

The following tables compare select benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2022** | 2021 | Change | **2022** | 2021 | Change |
| **Benchmark Averages** | | | | | | |
| WTI oil (US$/bbl) (1) | **91.56** | 70.56 | 21.00 | **98.09** | 64.82 | 33.27 |
| MEH oil (US$/bbl) (2) | **96.15** | 71.64 | 24.51 | **101.76** | 66.05 | 35.71 |
| MEH oil differential to WTI (US$/bbl) | **4.59** | 1.08 | 3.51 | **3.67** | 1.23 | 2.44 |
| Edmonton par oil ($/bbl) (3) | **116.79** | 83.78 | 33.01 | **123.41** | 75.88 | 47.53 |
| Edmonton par oil differential to WTI (US$/bbl) | **(2.13)** | (4.07) | 1.94 | **(1.89)** | (4.19) | 2.30 |
| WCS heavy oil ($/bbl) (4) | **93.62** | 71.81 | 21.81 | **105.65** | 65.47 | 40.18 |
| WCS heavy oil differential to WTI (US$/bbl) | **(19.87)** | (13.57) | (6.30) | **(15.74)** | (12.51) | (3.23) |
| AECO natural gas ($/mcf) (5) | **5.81** | 3.54 | 2.27 | **5.56** | 3.11 | 2.45 |
| NYMEX natural gas (US$/mmbtu) (6) | **8.20** | 4.01 | 4.19 | **6.77** | 3.18 | 3.59 |
| CAD/USD average exchange rate | **1.3059** | 1.2601 | 0.0458 | **1.2829** | 1.2515 | 0.0314 |

*(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.*
*(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.*
*(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.*
*(4) WCS refers to the average posting price for the benchmark WCS heavy oil.*
*(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").*
*(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.*

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| **Average Realized Sales Prices** | | | | | | |
| Light oil and condensate ($/bbl) (1) | **$ 115.51** | **$ 122.43** | **$ 118.99** | $ 82.14 | $ 88.01 | $ 85.29 |
| Heavy oil, net of blending and other expense ($/bbl) (2) | **84.38** | **—** | **84.38** | 62.70 | — | 62.70 |
| NGL ($/bbl) (1) | **46.01** | **43.43** | **44.07** | 36.92 | 41.94 | 41.08 |
| Natural gas ($/mcf) (1) | **4.96** | **9.88** | **6.82** | 3.71 | 5.00 | 4.29 |
| Total sales, net of blending and other expense ($/boe) (2) | **$ 84.30** | **$ 94.59** | **$ 87.68** | $ 61.69 | $ 67.11 | $ 63.85 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| **Average Realized Sales Prices** | | | | | | |
| Light oil and condensate ($/bbl) (1) | **$ 121.19** | **$ 128.65** | **$ 124.95** | $ 73.29 | $ 80.98 | $ 77.33 |
| Heavy oil, net of blending and other expense ($/bbl) (2) | **95.10** | **—** | **95.10** | 55.34 | — | 55.34 |
| NGL ($/bbl) (1) | **46.29** | **44.91** | **45.25** | 27.25 | 36.28 | 34.14 |
| Natural gas ($/mcf) (1) | **5.56** | **8.29** | **6.58** | 3.26 | 5.42 | 4.20 |
| Total sales, net of blending and other expense ($/boe) (2) | **$ 91.68** | **$ 96.79** | **$ 93.40** | $ 54.41 | $ 62.92 | $ 57.69 |

*(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

### Average Realized Sales Prices

Our total sales, net of blending and other expense per boe[1] was $87.68/boe for Q3/2022 and $93.40/bbl for YTD 2022 compared to $63.85/boe for Q3/2021 and $57.69/boe for YTD 2021. In Canada, our realized price of $84.30/boe for Q3/2022 was $22.61/boe higher than $61.69/boe for Q3/2021. Our realized price in the U.S. was $94.59/boe in Q3/2022 which is $27.48/boe higher than $67.11/boe in Q3/2021. The increase in our realized price in Canada and the U.S. for Q3/2022 and YTD 2022 was a result of higher North American benchmark prices relative to the same periods of 2021.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price[2] was $115.51/bbl for Q3/2022 and $121.19/bbl for YTD 2022 compared to $82.14/bbl for Q3/2021 and $73.29/bbl for YTD 2021. Our realized light oil and condensate price for Q3/2022 and YTD 2022 increased with the improvement in the benchmark price and represents discounts to the Edmonton par price of $1.28/bbl and $2.22/bbl for Q3/2022 and YTD 2022, respectively, which is consistent with a discount of $1.64/bbl in Q3/2021 and $2.59/bbl in YTD 2021.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $122.43/bbl for Q3/2022 and $128.65/bbl for YTD 2022 compared to $88.01/bbl for Q3/2021 and $80.98/bbl for YTD 2021. Expressed in U.S. dollars, our realized light oil and condensate price of US$93.75/bbl for Q3/2022 and US$100.28/bbl for YTD 2022 represents discounts to MEH of US$2.40/bbl and US$1.48/bbl Q3/2022 and YTD 2022, respectively, which is consistent with discounts of US$1.80/bbl for Q3/2021 and US$1.34/bbl for YTD 2021.

Our realized heavy oil price, net of blending and other expense[1] averaged $84.38/bbl in Q3/2022 and $95.10/bbl in YTD 2022 compared to $62.70/bbl in Q3/2021 and $55.34/bbl in YTD 2021. Our realized heavy oil, net of blending and other expense for Q3/2022 and YTD 2022 was $21.68/bbl and $39.76/bbl higher relative to Q3/2021 and YTD 2021, respectively, which is consistent with a $21.81/bbl and $40.18/bbl increase in the WCS benchmark price over the same periods.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Our realized NGL price[2] was $44.07/bbl in Q3/2022 or 37% of WTI (expressed in Canadian dollars) and $45.25/bbl in YTD 2022 or 36% of WTI (expressed in Canadian dollars) compared to $41.08/bbl or 46% of WTI (expressed in Canadian dollars) in Q3/2021 and $34.14/bbl or 42% of WTI (expressed in Canadian dollars) in YTD 2021. The increase in our realized price is primarily a result of higher WTI pricing in 2022 relative to the comparative periods of 2021 as our realization as a percentage of WTI was slightly lower in 2022.

We compare our realized natural gas price in Canada to the AECO benchmark price and to the NYMEX benchmark in the U.S.. Our realized natural gas price[2] in Canada was $4.96/mcf for Q3/2022 and $5.56/mcf for YTD 2022 compared to $3.71/mcf in Q3/2021 and $3.26/mcf for YTD 2021. In the U.S., our realized natural gas price was US$7.57/mcf for Q3/2022 and US$6.46/mcf for YTD 2022 compared to US$3.97/mcf for Q3/2021 and US$4.33/mcf for YTD 2021. The increase in our realized gas price in Canada and the U.S. is relatively consistent with the increases in the AECO and NYMEX benchmarks in 2022 compared to the same periods of 2021.

*(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.*

## PETROLEUM AND NATURAL GAS SALES

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Oil sales | | | | | | |
| Light oil and condensate | **$ 175,447** | **$ 188,521** | **$ 363,968** | $ 124,930 | $ 154,511 | $ 279,441 |
| Heavy oil | **267,958** | **—** | **267,958** | 146,468 | — | 146,468 |
| NGL | **7,929** | **22,627** | **30,556** | 4,177 | 22,932 | 27,109 |
| Total oil sales | **451,334** | **211,148** | **662,482** | 275,575 | 177,443 | 453,018 |
| Natural gas sales | **22,374** | **27,209** | **49,583** | 17,148 | 18,570 | 35,718 |
| Total petroleum and natural gas sales | **473,708** | **238,357** | **712,065** | 292,723 | 196,013 | 488,736 |
| Blending and other expense | **(40,945)** | **—** | **(40,945)** | (19,581) | — | (19,581) |
| Total sales, net of blending and other expense (1) | **$ 432,763** | **$ 238,357** | **$ 671,120** | $ 273,142 | $ 196,013 | $ 469,155 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Oil sales | | | | | | |
| Light oil and condensate | **$ 548,588** | **$ 591,946** | **$ 1,140,534** | $ 342,744 | $ 418,498 | $ 761,242 |
| Heavy oil | **858,497** | **—** | **858,497** | 385,288 | — | 385,288 |
| NGL | **23,701** | **69,529** | **93,230** | 12,327 | 52,870 | 65,197 |
| Total oil sales | **1,430,786** | **661,475** | **2,092,261** | 740,359 | 471,368 | 1,211,727 |
| Natural gas sales | **77,823** | **69,975** | **147,798** | 45,812 | 58,253 | 104,065 |
| Total petroleum and natural gas sales | **1,508,609** | **731,450** | **2,240,059** | 786,171 | 529,621 | 1,315,792 |
| Blending and other expense | **(139,280)** | **—** | **(139,280)** | (56,668) | — | (56,668) |
| Total sales, net of blending and other expense (1) | **$ 1,369,329** | **$ 731,450** | **$ 2,100,779** | $ 729,503 | $ 529,621 | $ 1,259,124 |

*(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

Total sales, net of blending and other expense, of $671.1 million for Q3/2022 increased $202.0 million from $469.2 million reported for Q3/2021 while total sales, net of blending and other expense, of $2.1 billion for YTD 2022 increased $841.7 million from $1.3 billion reported for YTD 2021. The increase in total sales is primarily a result of higher realized pricing consistent with the increase in benchmark pricing along with a modest increase in production due to our successful development program in Canada.

In Canada, total sales, net of blending and other expense, was $432.8 million for Q3/2022 which is an increase of $159.6 million from $273.1 million reported for Q3/2021. The increase in total petroleum and natural gas sales was the result of higher realized pricing and increased production volumes for Q3/2022 relative to Q3/2021. Our increased realized price resulted in a $116.0 million increase in total sales, net of blending and other expense, while an increase in production contributed to a $43.6 million increase in total sales, net of blending and other expense, relative to Q3/2021. Improvements in benchmark prices was the primary factor contributing to our total sales, net of blending and other expense, increasing to $1.4 billion in YTD 2022 from $729.5 million in YTD 2021.

In the U.S., petroleum and natural gas sales were $238.4 million for Q3/2022 which is an increase of $42.3 million from $196.0 million reported for Q3/2021. Total petroleum and natural gas sales increased $69.2 million due to higher realized pricing for Q3/2022 relative to Q3/2021 while lower production resulted in a $26.9 million decrease in total sales relative to Q3/2021. Higher realized pricing in YTD 2022 resulted in petroleum and natural gas sales of $731.5 million which was $201.8 million higher than $529.6 million in YTD 2021 despite lower production in YTD 2022 relative to YTD 2021.

## ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for % and per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Royalties | **$ 75,901** | **$ 71,093** | **$ 146,994** | $ 32,679 | $ 57,844 | $ 90,523 |
| Average royalty rate (1)(2) | **17.5 %** | **29.8 %** | **21.9 %** | 12.0 % | 29.5 % | 19.3 % |
| Royalties per boe (3) | **$ 14.78** | **$ 28.21** | **$ 19.21** | $ 7.38 | $ 19.80 | $ 12.32 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for % and per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Royalties | **$ 224,710** | **$ 216,563** | **$ 441,273** | $ 83,536 | $ 155,468 | $ 239,004 |
| Average royalty rate (1)(2) | **16.4 %** | **29.6 %** | **21.0 %** | 11.5 % | 29.4 % | 19.0 % |
| Royalties per boe (3) | **$ 15.04** | **$ 28.66** | **$ 19.62** | $ 6.23 | $ 18.47 | $ 10.95 |

*(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.*

Royalties for Q3/2022 were $147.0 million or 21.9% of total sales, net of blending and other expense, compared to $90.5 million or 19.3% for Q3/2021. Total royalties for YTD 2022 were $441.3 million or 21.0% of total sales, net of blending and other expense, compared to $239.0 million or 19.0% for YTD 2021. Total royalty expense was higher for Q3/2022 and YTD 2022 due to higher total sales, net of blending and other expense, along with a slight increase in our royalty rate relative to the same periods of 2021. Our royalty rates of 21.9% for Q3/2022 and 21.0% for YTD 2022 were higher than 19.3% for Q3/2021 and 19.0% for YTD 2021 due to a higher royalty rate on our Canadian properties as a result of higher commodity prices. Our average royalty rate of 21.0% for YTD 2022 is at the low end of our annual guidance range of 21.0% - 22.0% for 2022.

Our Canadian royalty rates of 17.5% for Q3/2022 and 16.4% for YTD 2022 were higher than 12.0% for Q3/2021 and 11.5% for YTD 2021 due to higher benchmark commodity prices which resulted in a higher royalty rate on our Canadian properties in 2022 relative to 2021. In the U.S., royalties averaged 29.8% and 29.6% of total sales for Q3/2022 and YTD 2022 respectively, which is consistent with 29.5% for Q3/2021 and 29.4% for YTD 2021 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

## OPERATING EXPENSE

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Operating expense | **$ 83,141** | **$ 26,998** | **$ 110,139** | $ 63,301 | $ 20,895 | $ 84,196 |
| Operating expense per boe (1) | **$ 16.19** | **$ 10.71** | **$ 14.39** | $ 14.30 | $ 7.15 | $ 11.46 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Operating expense | **$ 244,152** | **$ 74,179** | **$ 318,331** | $ 186,455 | $ 61,190 | $ 247,645 |
| Operating expense per boe (1) | **$ 16.35** | **$ 9.82** | **$ 14.15** | $ 13.91 | $ 7.27 | $ 11.35 |

*(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period.*

Total operating expense was $110.1 million ($14.39/boe) for Q3/2022 and $318.3 million ($14.15/boe) for YTD 2022 compared to $84.2 million ($11.46/boe) for Q3/2021 and $247.6 million ($11.35/boe) for YTD 2021. Operating expense for both periods of 2022 increased in total and per boe reflecting increased production and cost inflation throughout our operations in 2022 relative to 2021. Operating expense of $14.15 for YTD 2022 is consistent with our annual guidance range of $13.75 - $14.25/boe for 2022.

In Canada, operating expense was $83.1 million ($16.19/boe) for Q3/2022 and $244.2 million ($16.35/boe) for YTD 2022 compared to $63.3 million ($14.30/boe) for Q3/2021 and $186.5 million ($13.91/boe) for YTD 2021. U.S. operating expense was $27.0 million ($10.71/boe) for Q3/2022 and $74.2 million ($9.82/boe) for YTD 2022 compared to $20.9 million ($7.15/boe) for Q3/2021 and $61.2 million ($7.27/boe) in YTD 2021. Our U.S. operating expenses expressed in U.S. dollars, per unit operating expense was US$8.20/boe in Q3/2022 and US$7.65/boe in YTD 2022 which was higher than US$5.67/boe for Q3/2021 and US$5.81/boe in YTD 2021. The increase in per unit operating expense in Canada and the U.S. was primarily due to increased costs from energy inputs resulting in higher fuel, electricity and hauling costs along with additional workover and maintenance activity in 2022 relative to 2021.

## TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates.

The following table compares our transportation expense for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Transportation expense | **$ 12,771** | **$ —** | **$ 12,771** | $ 7,818 | $ — | $ 7,818 |
| Transportation expense per boe (1) | **$ 2.49** | **$ —** | **$ 1.67** | $ 1.77 | $ — | $ 1.06 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands except for per boe)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Transportation expense | **$ 33,744** | **$ —** | **$ 33,744** | $ 24,092 | $ — | $ 24,092 |
| Transportation expense per boe (1) | **$ 2.26** | **$ —** | **$ 1.50** | $ 1.80 | $ — | $ 1.10 |

*(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period.*

Transportation expense was $12.8 million ($1.67/boe) for Q3/2022 and $33.7 million ($1.50/boe) for YTD 2022 compared to $7.8 million ($1.06/boe) for Q3/2021 and $24.1 million ($1.10/boe) for YTD 2021. Total transportation expense and per unit costs are higher in Q3/2022 and YTD 2022 as a result of additional heavy oil production along with higher trucking rates relative to the same periods of 2021 due to higher fuel costs. Per unit transportation expense of $1.50/boe for YTD 2022 is at the low end of our annual guidance of $1.50 - $1.60/boe for 2022.

## BLENDING AND OTHER EXPENSE

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense was $40.9 million for Q3/2022 and $139.3 million for YTD 2022 compared to $19.6 million for Q3/2021 and $56.7 million for YTD 2021. Higher blending and other expense reflects an increase in the price of condensate purchased as diluent along with an increase in heavy oil production shipped via pipeline in 2022 relative to 2021.

## FINANCIAL DERIVATIVES

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our free cash flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Realized financial derivatives loss | | | | | | |
| Crude oil | **$ (66,582)** | $ (50,384) | $ (16,198) | **$ (258,180)** | $ (108,658) | $ (149,522) |
| Natural gas | **(9,826)** | (3,521) | (6,305) | **(26,636)** | (5,039) | (21,597) |
| Total | **$ (76,408)** | $ (53,905) | $ (22,503) | **$ (284,816)** | $ (113,697) | $ (171,119) |
| Unrealized financial derivatives gain (loss) | | | | | | |
| Crude oil | **$ 189,613** | $ 1,520 | $ 188,093 | **$ 98,111** | $ (165,019) | $ 263,130 |
| Natural gas | **4,018** | (13,190) | 17,208 | **(3,253)** | (22,475) | 19,222 |
| Equity total return swap ("Equity TRS") | **(3,160)** | 2,729 | (5,889) | **(1,880)** | 8,086 | (9,966) |
| Total | **$ 190,471** | $ (8,941) | $ 199,412 | **$ 92,978** | $ (179,408) | $ 272,386 |
| Total financial derivatives gain (loss) | | | | | | |
| Crude oil | **$ 123,031** | $ (48,864) | $ 171,895 | **$ (160,069)** | $ (273,677) | $ 113,608 |
| Natural gas | **(5,808)** | (16,711) | 10,903 | **(29,889)** | (27,514) | (2,375) |
| Equity TRS | **(3,160)** | 2,729 | (5,889) | **(1,880)** | 8,086 | (9,966) |
| Total | **$ 114,063** | $ (62,846) | $ 176,909 | **$ (191,838)** | $ (293,105) | $ 101,267 |

We recorded a total financial derivative gain of $114.1 million for Q3/2022 and a loss of $191.8 million for YTD 2022 compared to a loss of $62.8 million for Q3/2021 and a loss of $293.1 million for YTD 2021. The realized financial derivatives loss of $76.4 million for Q3/2022 and $284.8 million for YTD 2022 were primarily a result of the market prices for crude oil and natural gas settling at levels above those set in our derivative contracts. The unrealized gain of $190.5 million for Q3/2022 and $93.0 million for YTD 2022 reflect changes in forecasted crude oil pricing used to revalue the unsettled notional volume outstanding on our crude oil contracts in place at September 30, 2022 relative to June 30, 2022 and December 31, 2021. The fair value of our financial derivative contracts resulted in a net liability of $32.4 million at September 30, 2022 compared to a net liability of $222.9 million at June 30, 2022 and a net liability of $125.4 million at December 31, 2021.

We had the following commodity financial derivative contracts as at November 3, 2022.

| | Period | Volume | Price/Unit [(1)] | Index |
|---|---|---|---|---|
| **Oil** | | | | |
| Basis Swap | Oct 2022 to Dec 2022 | 12,000 bbl/d | WTI less US$12.40/bbl | WCS |
| Basis Swap | Oct 2022 to Dec 2022 | 6,750 bbl/d | WTI less US$3.73/bbl | MSW |
| Fixed Sell | Oct 2022 to Dec 2022 | 10,000 bbl/d | US$53.50/bbl | WTI |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 1,500 bbl/d | US$40.00/US$50.00/US$58.10 | WTI |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,000 bbl/d | US$46.00/US$56.00/US$66.72 | WTI |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 bbl/d | US$47.00/US$57.00/US$67.00 | WTI |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 bbl/d | US$50.00/US$60.00/US$70.00 | WTI |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,000 bbl/d | US$53.00/US$63.50/US$72.90 | WTI |
| 3-way option [(2)] | Jan 2023 to Dec 2023 | 2,000 bbl/d | US$55.00/US$66.00/US$84.00 | WTI |
| 3-way option [(2)] | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$60.00/US$75.00/US$91.54 | WTI |
| 3-way option [(2)] | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$65.00/US$85.00/US$100.00 | WTI |
| 3-way option [(2)] | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$65.00/US$85.00/US$106.50 | WTI |
| **Natural Gas** | | | | |
| Fixed Sell | Oct 2022 to Dec 2022 | 5,000 GJ/d | $2.53/GJ | AECO 7A |
| Fixed Sell | Oct 2022 to Dec 2022 | 14,250 GJ/d | $2.84/GJ | AECO 5A |
| Fixed Sell | Oct 2022 to Dec 2022 | 1,000 mmbtu/d | US$2.94/mmbtu | NYMEX |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.25/US$2.75/US$3.06 | NYMEX |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 1,500 mmbtu/d | US$2.60/US$2.91/US$3.56 | NYMEX |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.60/US$3.00/US$3.83 | NYMEX |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.65/US$2.90/US$3.40 | NYMEX |
| 3-way option [(2)] | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$3.00/US$3.75/US$4.40 | NYMEX |

*(1) Based on the weighted average price per unit for the period.*

*(2) Producer 3-way option consists of a sold put, a bought put and a sold call. To illustrate, in a US$50.00/US$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.*

## OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ per boe except for volume)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Total production (boe/d) | **55,803** | **27,391** | **83,194** | 48,124 | 31,748 | 79,872 |
| Operating netback: | | | | | | |
| Total sales, net of blending and other expense (1) | **$ 84.30** | **$ 94.59** | **$ 87.68** | $ 61.69 | $ 67.11 | $ 63.85 |
| Less: | | | | | | |
| Royalties (2) | **(14.78)** | **(28.21)** | **(19.21)** | (7.38) | (19.80) | (12.32) |
| Operating expense (2) | **(16.19)** | **(10.71)** | **(14.39)** | (14.30) | (7.15) | (11.46) |
| Transportation expense (2) | **(2.49)** | **—** | **(1.67)** | (1.77) | — | (1.06) |
| Operating netback (1) | **$ 50.84** | **$ 55.67** | **$ 52.41** | $ 38.24 | $ 40.16 | $ 39.01 |
| Realized financial derivatives loss (3) | **—** | **—** | **(9.98)** | — | — | (7.34) |
| Operating netback after financial derivatives (1) | **$ 50.84** | **$ 55.67** | **$ 42.43** | $ 38.24 | $ 40.16 | $ 31.67 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ per boe except for volume)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Total production (boe/d) | **54,711** | **27,681** | **82,392** | 49,108 | 30,834 | 79,942 |
| Operating netback: | | | | | | |
| Total sales, net of blending and other expense (1) | **$ 91.68** | **$ 96.79** | **$ 93.40** | $ 54.41 | $ 62.92 | $ 57.69 |
| Less: | | | | | | |
| Royalties (2) | **(15.04)** | **(28.66)** | **(19.62)** | (6.23) | (18.47) | (10.95) |
| Operating expense (2) | **(16.35)** | **(9.82)** | **(14.15)** | (13.91) | (7.27) | (11.35) |
| Transportation expense (2) | **(2.26)** | **—** | **(1.50)** | (1.80) | — | (1.10) |
| Operating netback (1) | **$ 58.03** | **$ 58.31** | **$ 58.13** | $ 32.47 | $ 37.18 | $ 34.29 |
| Realized financial derivatives loss (3) | **—** | **—** | **(12.66)** | — | — | (5.21) |
| Operating netback after financial derivatives (1) | **$ 58.03** | **$ 58.31** | **$ 45.47** | $ 32.47 | $ 37.18 | $ 29.08 |

*(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.*
*(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.*

Our operating netback of $52.41/boe for Q3/2022 and $58.13/boe for YTD 2022 was higher than $39.01/boe for Q3/2021 and $34.29/boe for YTD 2021 due to the increase in benchmark pricing in Canada and the U.S. which resulted in higher per unit sales net of royalties. Total operating and transportation expense of $16.06/boe for Q3/2022 and $15.65/boe for YTD 2022 were higher than $12.52/boe for Q3/2021 and $12.45/boe for YTD 2021 due to inflation which resulted in higher fuel, electricity and hauling costs along with increased workover and maintenance activity in YTD 2022. Including realized losses on financial derivatives our operating netback was $42.43/boe for Q3/2022 and $45.47/boe for YTD 2022 compared to $31.67/boe for Q3/2021 and $29.08/boe for YTD 2021.

## GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the three and nine months ended September 30, 2022 and 2021.

| ($ thousands except for per boe) | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Gross general and administrative expense | **$ 13,782** | $ 11,251 | $ 2,531 | **$ 39,511** | $ 31,871 | $ 7,640 |
| Overhead recoveries | **(1,779)** | (1,271) | (508) | **(4,186)** | (2,548) | (1,638) |
| General and administrative expense | **$ 12,003** | $ 9,980 | $ 2,023 | **$ 35,325** | $ 29,323 | $ 6,002 |
| General and administrative expense per boe (1) | **$ 1.57** | $ 1.36 | $ 0.21 | **$ 1.57** | $ 1.34 | $ 0.23 |

*(1) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period.*

G&A expense was $12.0 million ($1.57/boe) for Q3/2022 and $35.3 million ($1.57/boe) for YTD 2022 compared to $10.0 million ($1.36/boe) for Q3/2021 and $29.3 million ($1.34/boe) for YTD 2021. G&A expense for Q3/2022 and YTD 2022 was higher relative to the same periods of 2021 due to higher staffing costs associated with increased exploration and development expenditures in Canada during 2022. G&A expense of $1.57/boe during YTD 2022 is consistent with our revised annual guidance of $1.57/boe for 2022.

## FINANCING AND INTEREST EXPENSE

Financing and interest expense includes interest on our credit facilities, long-term notes and lease obligations as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the three and nine months ended September 30, 2022 and 2021.

| ($ thousands except for per boe) | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Interest on credit facilities | **$ 5,788** | $ 3,256 | $ 2,532 | **$ 12,897** | $ 9,842 | $ 3,055 |
| Interest on long-term notes | **13,935** | 19,481 | (5,546) | **47,635** | 60,734 | (13,099) |
| Interest on lease obligations | **51** | 56 | (5) | **$ 143** | $ 174 | (31) |
| Cash interest | **$ 19,774** | $ 22,793 | $ (3,019) | **$ 60,675** | $ 70,750 | $ (10,075) |
| Accretion of debt issue costs | **1,242** | 1,733 | (491) | **4,671** | 3,272 | 1,399 |
| Accretion of asset retirement obligations | **4,412** | 3,273 | 1,139 | **11,403** | 8,938 | 2,465 |
| Early redemption expense | **325** | 1,229 | (904) | **325** | 872 | (547) |
| Financing and interest expense | **$ 25,753** | $ 29,028 | $ (3,275) | **$ 77,074** | $ 83,832 | $ (6,758) |
| Cash interest per boe (1) | **$ 2.58** | $ 3.10 | $ (0.52) | **$ 2.70** | $ 3.24 | $ (0.54) |
| Financing and interest expense per boe (1) | **$ 3.36** | $ 3.95 | $ (0.59) | **$ 3.43** | $ 3.84 | $ (0.41) |

*(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.*

Financing and interest expense was $25.8 million ($3.36/boe) for Q3/2022 and $77.1 million ($3.43/boe) for YTD 2022 compared to $29.0 million ($3.95/boe) for Q3/2021 and $83.8 million ($3.84/boe) for YTD 2021. Lower debt levels have resulted in reduced financing and interest expense in both periods of 2022 relative to 2021.

Cash interest of $19.8 million ($2.58/boe) for Q3/2022 and $60.7 million ($2.70/boe) for YTD 2022 is lower than $22.8 million ($3.10/boe) for Q3/2021 and $70.8 million ($3.24/boe) for YTD 2021 as we had less debt outstanding during 2022. The interest on our U.S. dollar denominated long-term notes was lower as the average principal amount outstanding was lower during YTD 2022 due to the repurchase and redemption of US$200.0 million of long-term notes in 2021 and US$226.8 million of long-term notes in YTD 2022. Interest on our credit facilities in Q3/2022 and YTD 2022 was higher than the same periods of 2021 and is consistent with the increase in benchmark borrowing rates. The weighted average interest rate applicable to our credit facilities was 4.1% for Q3/2022 and 3.1% for YTD 2022 which is higher than 2.2% for both Q3/2021 and YTD 2021.

Financing and interest expense for YTD 2022 was lower than YTD 2021 which was primarily the result of the repurchase and redemption of the 2024 senior notes and also reflects a higher discount rate on our asset retirement obligations for YTD 2022.

Cash interest expense of $2.70/boe for YTD 2022 is above our revised annual guidance of $2.58/boe for 2022 as we expect a reduction in our net debt during the remainder of the year along with higher production.

## EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $6.6 million for Q3/2022 and $17.3 million for YTD 2022 compared to $6.8 million for Q3/2021 and $10.7 million for YTD 2021.

## DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and nine months ended September 30, 2022 and 2021.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ thousands except for per boe)* | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Depletion | **$ 142,651** | $ 125,681 | $ 16,970 | **$ 422,906** | $ 328,171 | $ 94,735 |
| Depreciation | **1,526** | 1,371 | 155 | **4,348** | 3,948 | 400 |
| Depletion and depreciation | **$ 144,177** | $ 127,052 | $ 17,125 | **$ 427,254** | $ 332,119 | $ 95,135 |
| Depletion and depreciation per boe [(1)] | **$ 18.84** | $ 17.29 | $ 1.55 | **$ 18.99** | $ 15.22 | $ 3.77 |

*(1) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period.*

Depletion and depreciation expense was $144.2 million ($18.84/boe) for Q3/2022 and $427.3 million ($18.99/boe) for YTD 2022 compared to $127.1 million ($17.29/boe) for Q3/2021 and $332.1 million ($15.22/boe) for YTD 2021. Total depletion and depreciation expense as well as the depletion rate per boe were higher in both periods of 2022 relative to 2021 as a result of $1.5 billion of impairment reversals recorded during 2021 which increased the depletable base of our U.S. and Canadian assets.

## IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGU") at September 30, 2022.

### 2021 Impairment Reversals

We identified indicators of impairment reversal at June 30, 2021 and December 31, 2021 due to the increase in forecasted commodity prices and our estimates of proved plus probable reserves which resulted in total impairment reversals of $1.5 billion being recorded during 2021. At June 30, 2021 we recorded a $1.1 billion impairment reversal as the estimated recoverable amount of our six CGUs exceeded their carrying values. At December 31, 2021 we recorded a $0.4 billion impairment reversal as the estimated recoverable amount of three CGUs exceeded their carrying amounts.

## SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with our Share Award Incentive Plan is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with our Incentive Award Plan is recognized in net income or loss over the vesting period of the awards with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense associated with the Deferred Share Unit Plan is recognized in net income or loss on the grant date with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $3.1 million for Q3/2022 and $10.0 million for YTD 2022 which is slightly higher than $2.5 million for Q3/2021 and $8.3 million for YTD 2021. The total expense for YTD 2022 is comprised of non-cash compensation expense of $2.7 million (YTD 2021 - $4.6 million) related to the Share Award Incentive Plan and cash compensation expense of $7.3 million (YTD 2021 - $3.7 million) related to the Incentive Award Plan and the Deferred Share Unit Plan.

## FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ thousands except for exchange rates)* | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Unrealized foreign exchange loss | **$ 39,799** | $ 7,545 | $ 32,254 | **$ 52,750** | $ 3,223 | $ 49,527 |
| Realized foreign exchange gain | **(894)** | (79) | (815) | **(481)** | (818) | 337 |
| Foreign exchange loss | **$ 38,905** | $ 7,466 | $ 31,439 | **$ 52,269** | $ 2,405 | $ 49,864 |
| CAD/USD exchange rates: | | | | | | |
| At beginning of period | **1.2872** | 1.2405 | | **1.2656** | 1.2755 | |
| At end of period | **1.3700** | 1.2750 | | **1.3700** | 1.2750 | |

We recorded a foreign exchange loss of $38.9 million for Q3/2022 and $52.3 million for YTD 2022 compared to a loss of $7.5 million for Q3/2021 and $2.4 million for YTD 2021.

The unrealized foreign exchange loss of $39.8 million for Q3/2022 and $52.8 million for YTD 2022 is primarily related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2022 compared to June 30, 2022 and December 31, 2021. The unrealized foreign exchange loss for Q3/2021 and YTD 2021 relates to changes in the reported amount of our long-term notes and intercompany notes outstanding at September 30, 2021 compared to June 30, 2021 and December 31, 2020.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $0.9 million for Q3/2022 and $0.5 million for YTD 2022 compared to a gain of $0.1 million for Q3/2021 and $0.8 million for YTD 2021.

## INCOME TAXES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Current income tax expense | **$ 703** | $ 486 | $ 217 | **$ 2,753** | $ 894 | $ 1,859 |
| Deferred income tax expense (recovery) | **18,475** | 10,248 | 8,227 | **(8,937)** | 71,963 | (80,900) |
| Total income tax expense (recovery) | **$ 19,178** | $ 10,734 | $ 8,444 | **$ (6,184)** | $ 72,857 | $ (79,041) |

Current income tax expense was $0.7 million for Q3/2022 and $2.8 million for YTD 2022 compared to $0.5 million for Q3/2021 and $0.9 million for YTD 2021.

We recorded deferred tax expense of $18.5 million for Q3/2022 and a recovery of $8.9 million for YTD 2022 compared to expense of $10.2 million for Q3/2021 and $72.0 million for YTD 2021. The deferred tax recovery recorded in YTD 2022 is primarily related to the effect of an internal debt restructuring offset by the income generated in our U.S. operations for the period. The deferred tax expense in YTD 2021 is primarily related to the impairment reversal recorded in our U.S. operating segment during YTD 2021.

As disclosed in the 2021 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

## NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three and nine months ended September 30, 2022 and 2021 are set forth in the following table.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | Change | **2022** | 2021 | Change |
| Petroleum and natural gas sales | **$ 712,065** | $ 488,736 | $ 223,329 | **$ 2,240,059** | $ 1,315,792 | $ 924,267 |
| Royalties | **(146,994)** | (90,523) | (56,471) | **(441,273)** | (239,004) | (202,269) |
| **Revenue, net of royalties** | **565,071** | 398,213 | 166,858 | **1,798,786** | 1,076,788 | 721,998 |
| | | | | | | |
| **Expenses** | | | | | | |
| Operating | **(110,139)** | (84,196) | (25,943) | **(318,331)** | (247,645) | (70,686) |
| Transportation | **(12,771)** | (7,818) | (4,953) | **(33,744)** | (24,092) | (9,652) |
| Blending and other | **(40,945)** | (19,581) | (21,364) | **(139,280)** | (56,668) | (82,612) |
| **Operating netback** (1) | **$ 401,216** | $ 286,618 | $ 114,598 | **$ 1,307,431** | $ 748,383 | $ 559,048 |
| General and administrative | **(12,003)** | (9,980) | (2,023) | **(35,325)** | (29,323) | (6,002) |
| Cash interest | **(19,774)** | (22,793) | 3,019 | **(60,675)** | (70,750) | 10,075 |
| Realized financial derivatives loss | **(76,408)** | (53,905) | (22,503) | **(284,816)** | (113,697) | (171,119) |
| Realized foreign exchange gain | **894** | 79 | 815 | **481** | 818 | (337) |
| Other expense | **(6,499)** | (78) | (6,421) | **(7,500)** | (16) | (7,484) |
| Current income tax expense | **(703)** | (486) | (217) | **(2,753)** | (894) | (1,859) |
| Share-based compensation - cash | **(2,435)** | (1,058) | (1,377) | **(7,244)** | (3,659) | (3,585) |
| **Adjusted funds flow** (2) | **$ 284,288** | $ 198,397 | $ 85,891 | **$ 909,599** | $ 530,862 | $ 378,737 |
| Exploration and evaluation | **(6,566)** | (6,766) | 200 | **(17,346)** | (10,718) | (6,628) |
| Depletion and depreciation | **(144,177)** | (127,052) | (17,125) | **(427,254)** | (332,119) | (95,135) |
| Share-based compensation - non-cash | **(637)** | (1,453) | 816 | **(2,715)** | (4,603) | 1,888 |
| Non-cash financing and accretion | **(5,979)** | (6,235) | 256 | **(16,399)** | (13,082) | (3,317) |
| Non-cash other income | **1,276** | 444 | 832 | **2,741** | 2,108 | 633 |
| Unrealized financial derivatives gain (loss) | **190,471** | (8,941) | 199,412 | **92,978** | (179,408) | 272,386 |
| Unrealized foreign exchange loss | **(39,799)** | (7,545) | (32,254) | **(52,750)** | (3,223) | (49,527) |
| Gain on dispositions | **4,566** | 2,112 | 2,454 | **5,007** | 6,092 | (1,085) |
| Impairment reversal | **—** | — | — | **—** | 1,126,415 | (1,126,415) |
| Deferred income tax (expense) recovery | **(18,475)** | (10,248) | (8,227) | **8,937** | (71,963) | 80,900 |
| **Net income for the period** | **$ 264,968** | $ 32,713 | $ 232,255 | **$ 502,798** | $ 1,050,361 | $ (547,563) |

*(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*

We generated adjusted funds flow of $284.3 million for Q3/2022 and $909.6 million for YTD 2022 compared to $198.4 million for Q3/2021 and $530.9 million for YTD 2021. The increase in adjusted funds flow for both periods of 2022 was primarily due to higher operating netback which increased $114.6 million from Q3/2021 and $559.0 million from YTD 2021 as a result of higher commodity prices that increased revenue, net of royalties. The increase in operating netback was partially offset by realized losses on financial derivatives of $76.4 million for Q3/2022 and $284.8 million for YTD 2022 which increased $22.5 million and $171.1 million relative to Q3/2021 and YTD 2021 when we recorded realized losses on financial derivatives of $53.9 million and $113.7 million respectively.

We reported net income of $265.0 million for Q3/2022 and $502.8 million for YTD 2022 compared to net income of $32.7 million reported for Q3/2021 and $1.1 billion for YTD 2021. Higher net income reported for YTD 2021 is primarily the result of a $1.1 billion impairment reversal that was recorded in Q2/2021.

## OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation gain of $117.0 million for Q3/2022 and $147.9 million for YTD 2022 relates to the change in value of our U.S. net assets and is due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2022 compared to June 30, 2022 and December 31, 2021. The CAD/USD exchange rate was 1.3700 CAD/USD as at September 30, 2022 compared to 1.2872 CAD/USD at June 30, 2022 and 1.2656 CAD/USD at December 31, 2021.

## CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2022 and 2021 are summarized as follows.

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Drilling, completion and equipping | **$ 103,523** | **$ 49,150** | **$ 152,673** | $ 67,177 | $ 18,460 | $ 85,637 |
| Facilities | **8,130** | **969** | **9,099** | 5,364 | 11 | 5,375 |
| Land, seismic and other | **5,497** | **184** | **5,681** | 2,958 | 265 | 3,223 |
| Exploration and development expenditures | **$ 117,150** | **$ 50,303** | **$ 167,453** | $ 75,499 | $ 18,736 | $ 94,235 |
| Property acquisitions | **$ —** | **$ —** | **$ —** | $ 89 | $ — | $ 89 |
| Proceeds from dispositions | **$ (25,460)** | **$ —** | **$ (25,460)** | $ (108) | $ (593) | $ (701) |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| *($ thousands)* | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Drilling, completion and equipping | **$ 247,785** | **$ 119,454** | **$ 367,239** | $ 129,230 | $ 90,092 | $ 219,322 |
| Facilities | **22,807** | **2,769** | **25,576** | 12,562 | 25 | 12,587 |
| Land, seismic and other | **24,569** | **524** | **25,093** | 6,597 | 802 | 7,399 |
| Exploration and development expenditures | **$ 295,161** | **$ 122,747** | **$ 417,908** | $ 148,389 | $ 90,919 | $ 239,308 |
| Property acquisitions | **$ 267** | **$ —** | **$ 267** | $ 114 | $ — | $ 114 |
| Proceeds from dispositions | **$ (25,501)** | **$ —** | **$ (25,501)** | $ (354) | $ (593) | $ (947) |

Exploration and development expenditures were $167.5 million for Q3/2022 and $417.9 million for YTD 2022 compared to $94.2 million for Q3/2021 and $239.3 million for YTD 2021. Exploration and development expenditures in Q3/2022 were higher compared to Q3/2021 as development increased with stronger commodity prices in 2022 along with inflationary pressures that have resulted in higher costs relative to 2021.

In Canada, exploration and development expenditures were $117.2 million in Q3/2022 and $295.2 million in YTD 2022 compared to $75.5 million in Q3/2021 and $148.4 million in YTD 2021. Drilling and completion spending of $103.5 million in Q3/2022 and $247.8 million in YTD 2022 reflects higher light and heavy oil development activity relative to Q3/2021 and YTD 2021 when we spent $67.2 million and $129.2 million respectively. We also invested $8.1 million on facilities and $5.5 million on land, seismic and other expenditures during Q3/2022 and we completed a minor non-core property disposition in our conventional business unit in West Central Alberta for proceeds of $25.5 million.

Total U.S. exploration and development expenditures were $50.3 million for Q3/2022 and $122.7 million for YTD 2022 compared to $18.7 million in Q3/2021 and $90.9 million during YTD 2021. Exploration and development expenditures for Q3/2022 included costs associated with drilling 14 (3.7 net) wells along with 19 (4.1 net) wells that we brought on production compared to drilling 11 (2.0 net) wells along with 17 (3.4 net) wells brought on production during Q3/2021. The timing and pace of development activity combined with inflationary pressures and weaker Canadian dollar resulted in exploration and development expenditures of $50.3 million for Q3/2022 and $122.7 million for YTD 2022 compared to $18.7 million and $90.9 million for the same periods of 2021.

Our exploration and development expenditures for YTD 2022 are consistent with expectations and we now expect full year expenditures of $515 million for 2022.

## CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At September 30, 2022, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, cash and the credit facilities.

In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties.

Management of debt levels is a priority for us in order to sustain operations and support our long-term plans. At September 30, 2022, net debt[(1)] of $1.11 billion was $296.2 million lower than $1.41 billion at December 31, 2021. The decrease in net debt for 2022 is primarily a result of the free cash flow[(2)] of $478.2 million generated during 2022 being allocated towards debt repayment which was partially offset by $141.3 million in common share repurchases completed in conjunction with our shareholder returns initiative.

In May 2022, we began repurchasing our common shares under a previously announced normal course issuer bid ("NCIB") as part of our shareholder return framework. During YTD 2022 we have spent $141.3 million to repurchase and cancel 21.6 million common shares, representing 3.8% of the total shares outstanding at the commencement of the NCIB.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve month basis. At September 30, 2022, our net debt to adjusted funds flow ratio[(1)] was 1.0 compared to a ratio of 1.9 as at December 31, 2021. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2021 is attributed to higher adjusted funds flow for the trailing twelve months ended September 30, 2022 and lower net debt at September 30, 2022.

### Credit Facilities

At September 30, 2022, the principal amount of borrowings outstanding under our credit facilities was $450.1 million. On April 1, 2022, we amended the credit facilities to expand our revolving facilities to US$850 million and extend maturity to April 1, 2026. The term loan facility was eliminated as part of this amendment.

The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. There are no mandatory principal payments required prior to maturity which could be extended upon our request. The credit facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the credit facilities was 4.1% for Q3/2022 and 3.1% for YTD 2022 compared to 2.2% for both Q3/2021 and YTD 2021. The interest rate on our credit facilities has increased with higher government benchmark rates in 2022 relative to 2021.

On July 25, 2022 we entered into a $20 million uncommitted unsecured demand revolving letter of credit facility (the "LC Facility"). Letters of credit under this facility are guaranteed by Export Development Canada and do not use available capacity under the credit facilities. As at September 30, 2022, we had $15.8 million of outstanding letters of credit under the LC Facility.

The agreements and associated amending agreements relating to the credit facilities are accessible on the SEDAR website at www.sedar.com.

*(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

### Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and our compliance therewith at September 30, 2022.

| Covenant Description | Position as at September 30, 2022 | Covenant |
|---|---|---|
| Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio) | **0.4:1:0** | 3.5:1.0 |
| Interest Coverage (3) (Minimum Ratio) | **14.8:1.0** | 2.0:1.0 |

*(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreements and is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at September 30, 2022, the Company's Senior Secured Debt totaled $450.1 million of principal amounts outstanding.*

*(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2022 was $1.2 billion.*

*(3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended September 30, 2022 were $81.8 million.*

### Long-Term Notes

We have one series of long-term notes outstanding that totals $648.2 million as at September 30, 2022. The long-term notes do not contain any financial maintenance covenants.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes"), and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). We redeemed the 5.125% Notes on February 20, 2020. During 2021, we redeemed and cancelled US$200 million of the 5.625% Notes and on June 1, 2022, we redeemed and cancelled the remaining US$200 million of the 5.625% Notes at par.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes"). The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. During the Q3/2022, Baytex repurchased and cancelled an aggregate principal amount of US$26.8 million of the 8.75% Notes.

### Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the nine months ended September 30, 2022, we issued 5.0 million common shares pursuant to our share-based compensation program and cancelled 21.6 million common shares repurchased under a NCIB. As at September 30, 2022, we had 547.6 million common shares issued and outstanding and no preferred shares issued and outstanding.

### Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of September 30, 2022 and the expected timing for funding these obligations are noted in the table below.

| *($ thousands)* | **Total** | Less than 1 year | 1-3 years | 3-5 years | Beyond 5 years |
|---|---|---|---|---|---|
| Trade and other payables | **$ 271,400** | $ 268,410 | $ 2,990 | $ — | $ — |
| Financial derivatives | **48,587** | 48,587 | — | — | — |
| Credit facilities - principal (1)(2) | **450,051** | — | — | 450,051 | — |
| Long-term notes - principal (2) | **648,207** | — | — | 648,207 | — |
| Interest on long-term notes (3) | **255,464** | 56,718 | 113,436 | 85,310 | — |
| Lease obligations (2) | **7,449** | 3,873 | 3,295 | 281 | — |
| Processing agreements | **6,971** | 1,193 | 1,216 | 838 | 3,724 |
| Transportation agreements | **54,840** | 10,813 | 26,610 | 14,673 | 2,744 |
| Total | **$ 1,742,969** | $ 389,594 | $ 147,547 | $ 1,199,360 | $ 6,468 |

*(1) On April 1, 2022 we extended the maturity of our credit facilities to April 1, 2026.*
*(2) Principal amount of instruments.*
*(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.*

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

## QUARTERLY FINANCIAL INFORMATION

| | 2022 | | | 2021 | | | | 2020 |
|---|---|---|---|---|---|---|---|---|
| *($ thousands, except per common share amounts)* | **Q3** | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 |
| Petroleum and natural gas sales | **712,065** | 854,169 | 673,825 | 552,403 | 488,736 | 442,354 | 384,702 | 233,636 |
| Net income (loss) | **264,968** | 180,972 | 56,858 | 563,239 | 32,713 | 1,052,999 | (35,352) | 221,160 |
| Per common share - basic | **0.48** | 0.32 | 0.10 | 1.00 | 0.06 | 1.87 | (0.06) | 0.39 |
| Per common share - diluted | **0.47** | 0.32 | 0.10 | 0.98 | 0.06 | 1.85 | (0.06) | 0.39 |
| Adjusted funds flow (1) | **284,288** | 345,704 | 279,607 | 214,766 | 198,397 | 175,883 | 156,582 | 82,176 |
| Per common share - basic | **0.51** | 0.61 | 0.49 | 0.38 | 0.35 | 0.31 | 0.28 | 0.15 |
| Per common share - diluted | **0.51** | 0.60 | 0.49 | 0.37 | 0.35 | 0.31 | 0.28 | 0.15 |
| Free cash flow (2) | **111,568** | 245,316 | 121,318 | 137,133 | 101,215 | 112,486 | 70,495 | 1,794 |
| Per common share - basic | **0.20** | 0.43 | 0.21 | 0.24 | 0.18 | 0.20 | 0.13 | — |
| Per common share - diluted | **0.20** | 0.43 | 0.21 | 0.24 | 0.18 | 0.20 | 0.13 | — |
| Cash flows from operating activities | **310,423** | 360,034 | 198,974 | 240,567 | 178,961 | 171,876 | 120,980 | 51,017 |
| Per common share - basic | **0.56** | 0.63 | 0.35 | 0.43 | 0.32 | 0.30 | 0.22 | 0.09 |
| Per common share - diluted | **0.56** | 0.63 | 0.35 | 0.42 | 0.31 | 0.30 | 0.22 | 0.09 |
| Exploration and development | **167,453** | 96,633 | 153,822 | 73,995 | 94,235 | 61,485 | 83,588 | 77,809 |
| Canada | **117,150** | 51,881 | 126,130 | 59,821 | 75,499 | 30,387 | 42,503 | 45,030 |
| U.S. | **50,303** | 44,752 | 27,692 | 14,174 | 18,736 | 31,098 | 41,085 | 32,779 |
| Property acquisitions | **—** | 208 | 59 | 1,443 | 89 | — | 25 | — |
| Proceeds from dispositions | **(25,460)** | (14) | (27) | (6,857) | (701) | (18) | (228) | (33) |
| Net debt (1) | **1,113,559** | 1,123,297 | 1,275,680 | 1,409,717 | 1,564,658 | 1,629,629 | 1,758,894 | 1,847,601 |
| Total assets (3) | **4,923,617** | 4,870,432 | 4,917,811 | 4,834,643 | 4,453,971 | 4,438,162 | 3,338,408 | 3,408,096 |
| Common shares outstanding | **547,615** | 560,139 | 569,214 | 564,213 | 564,213 | 564,182 | 564,111 | 561,227 |
| **Daily production** | | | | | | | | |
| Total production (boe/d) | **83,194** | 83,090 | 80,867 | 80,789 | 79,872 | 81,162 | 78,780 | 70,475 |
| Canada (boe/d) | **55,803** | 54,919 | 53,385 | 50,362 | 48,124 | 47,205 | 52,039 | 45,321 |
| U.S. (boe/d) | **27,391** | 28,170 | 27,482 | 30,428 | 31,748 | 33,957 | 26,741 | 25,154 |
| **Benchmark prices** | | | | | | | | |
| WTI oil (US$/bbl) | **91.56** | 108.41 | 94.29 | 77.19 | 70.56 | 66.07 | 57.84 | 42.66 |
| WCS heavy oil ($/bbl) | **93.62** | 122.05 | 100.99 | 78.82 | 71.81 | 67.03 | 57.46 | 43.46 |
| Edmonton par oil ($/bbl) | **116.79** | 137.79 | 115.66 | 93.29 | 83.78 | 77.28 | 66.58 | 50.24 |
| CAD/USD avg exchange rate | **1.3059** | 1.2766 | 1.2661 | 1.2600 | 1.2601 | 1.2279 | 1.2663 | 1.3031 |
| AECO natural gas ($/mcf) | **5.81** | 6.27 | 4.59 | 4.94 | 3.54 | 2.85 | 2.93 | 2.77 |
| NYMEX natural gas (US$/mmbtu) | **8.20** | 7.17 | 4.95 | 5.83 | 4.01 | 2.83 | 2.69 | 2.66 |
| Total sales, net of blending and other expense ($/boe) (2) | **87.68** | 105.44 | 86.89 | 70.42 | 63.85 | 57.19 | 51.84 | 34.35 |
| Royalties ($/boe) (3) | **(19.21)** | (22.69) | (16.86) | (13.47) | (12.32) | (11.04) | (9.44) | (5.83) |
| Operating expense ($/boe) (3) | **(14.39)** | (14.21) | (13.85) | (12.83) | (11.46) | (11.22) | (11.36) | (12.30) |
| Transportation expense ($/boe) (3) | **(1.67)** | (1.56) | (1.27) | (1.10) | (1.06) | (1.01) | (1.24) | (1.03) |
| **Operating netback ($/boe) (2)** | **52.41** | 66.98 | 54.91 | 43.02 | 39.01 | 33.92 | 29.80 | 15.19 |
| Financial derivatives (loss) gain ($/boe) (3) | **(9.98)** | (16.41) | (11.59) | (9.49) | (7.34) | (5.28) | (2.93) | 2.64 |
| **Operating netback after financial derivatives ($/boe) (2)** | **42.43** | 50.57 | 43.32 | 33.53 | 31.67 | 28.64 | 26.87 | 17.83 |

*(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*

*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

*(3) Previously disclosed amounts have been revised to conform with current period presentation.*

*(4) Calculated as royalties expense, operating expense, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.*

Our results for the previous eight quarters reflect the disciplined execution of our capital programs and management of production in response to fluctuations in the prices for the commodities we produce. Production of 70,475 boe/d in Q4/2020 reflects our efforts to manage capital and production levels in response to volatile commodity prices caused by the COVID-19 pandemic. Development activity increased as commodity prices began to climb in Q1/2021 and we have continued the pace of activity as commodity prices improved throughout 2021 and 2022. Strong well performance and our successful development programs have resulted in production of 83,194 boe/d for Q3/2022.

Prices began to strengthen in 2021 as measures to control the spread of COVID-19 were relaxed. Commodity prices continued to improve to multi-year highs in 2022 following Russia's invasion of Ukraine which created elevated uncertainty surrounding the global supply of oil. The impact of increased commodity prices is reflected in our realized sales price of $105.44/boe for Q2/2022 which is our strongest realized pricing in eight quarters. Our realized price of $87.68/boe for Q3/2022 reflects recent declines in crude oil prices caused by concern over future demand and economic slowdowns.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow(1) of $284.3 million for Q3/2022 reflects strong price realizations and production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) has decreased from $1.8 billion at Q4/2020 to $1.1 billion at Q3/2022 as free cash flow(2) of $901.3 million generated over the last eight quarters has been primarily directed towards debt repayment. The decrease in net debt due to free cash flow was partially offset by our shareholder return initiative which was implemented during Q2/2022 and resulted in the repurchase and cancellation of 21.6 million common shares for total consideration of $141.3 million as of Q3/2022.

*(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.*
*(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.*

## ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the AIF for the year ended December 31, 2021 for a full description of the risks associated with these regulations and how they may impact our business in the future. In addition to the Risk Factors discussed in the AIF for the year ended December 31, 2021, additional information related to our emissions and sustainability initiatives is available on our website.

### Reporting Regulations

Environmental reporting for public enterprises continues to evolve and we may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters* which sets forth additional reporting requirements for Canadian Public Companies. We continue to monitor developments on these reporting requirements and have not yet quantified the cost to comply with these regulations.

## OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2022, nor are any such arrangements outstanding as of the date of this MD&A.

## CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the nine months ended September 30, 2022. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2021.

## SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

### Non-GAAP Financial Measures

*Total sales, net of blending and other expense*

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

*Operating netback*

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| ($ thousands) | 2022 | 2021 | 2022 | 2021 |
| Petroleum and natural gas sales | $ 712,065 | $ 488,736 | $ 2,240,059 | $ 1,315,792 |
| Blending and other expense | (40,945) | (19,581) | (139,280) | (56,668) |
| Total sales, net of blending and other expense | 671,120 | 469,155 | 2,100,779 | 1,259,124 |
| Royalties | (146,994) | (90,523) | (441,273) | (239,004) |
| Operating expense | (110,139) | (84,196) | (318,331) | (247,645) |
| Transportation expense | (12,771) | (7,818) | (33,744) | (24,092) |
| Operating netback | 401,216 | 286,618 | 1,307,431 | 748,383 |
| Realized financial derivatives loss [(1)] | (76,408) | (53,905) | (284,816) | (113,697) |
| Operating netback after realized financial derivatives | $ 324,808 | $ 232,713 | $ 1,022,615 | $ 634,686 |

*(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 16 - Financial Instruments and Risk Management in the consolidated financial statements for the three and nine months ended September 30, 2022 for further information.*

*Free cash flow*

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

Free cash flow is reconciled to cash flows from operating activities in the following table.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| ($ thousands) | 2022 | 2021 | 2022 | 2021 |
| Cash flows from operating activities | $ 310,423 | $ 178,961 | $ 869,431 | $ 471,817 |
| Change in non-cash working capital | (30,734) | 17,631 | 29,560 | $ 54,830 |
| Additions to exploration and evaluation assets | — | (89) | (5,897) | (733) |
| Additions to oil and gas properties | (167,453) | (94,146) | (412,011) | (238,575) |
| Payments on lease obligations | (668) | (1,142) | (2,881) | (3,143) |
| Free cash flow | $ 111,568 | $ 101,215 | $ 478,202 | $ 284,196 |

**Non-GAAP Financial Ratios**

*Heavy oil, net of blending and other expense per bbl*

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP financial ratio that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

*Total sales, net of blending and other expense per boe*

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

*Average royalty rate*

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

*Operating netback per boe*

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

**Capital Management Measures**

*Net debt*

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by twelve-month trailing adjusted funds flow.

The following table summarizes our calculation of net debt.

| *($ thousands)* | **September 30, 2022** | December 31, 2021 |
|---|---|---|
| Credit facilities | **$ 447,475** | $ 505,171 |
| Unamortized debt issuance costs - Credit facilities (1) | **2,576** | 1,343 |
| Long-term notes | **639,679** | 874,527 |
| Unamortized debt issuance costs - Long-term notes (1) | **8,528** | 11,393 |
| Trade and other payables | **271,400** | 190,692 |
| Cash | **(4,410)** | — |
| Trade and other receivables | **(251,689)** | (173,409) |
| Net debt | **$ 1,113,559** | $ 1,409,717 |
| Net debt to adjusted funds flow | **1.0** | 1.9 |

*(1) Unamortized debt issuance costs were obtained from Note 6 - Credit Facilities and Note 7 - Long-term Notes from the consolidated financial statements for the three and nine months ended September 30, 2022. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.*

*Adjusted funds flow*

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirement obligations settled during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ thousands)* | **2022** | 2021 | **2022** | 2021 |
| Cash flow from operating activities | **$ 310,423** | $ 178,961 | **$ 869,431** | $ 471,817 |
| Change in non-cash working capital | **(30,734)** | 17,631 | **29,560** | 54,830 |
| Asset retirement obligations settled | **4,599** | 1,805 | **10,608** | 4,215 |
| Adjusted funds flow | **$ 284,288** | $ 198,397 | **$ 909,599** | $ 530,862 |

**INTERNAL CONTROL OVER FINANCIAL REPORTING**

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended September 30, 2022.

**FORWARD-LOOKING STATEMENTS**

*In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.*

*Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2022 guidance with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; and the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; we may issue debt or equity securities, sell assets or adjust capital spending.*

*These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices (well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.*

*Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

*The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.*

*There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.*

**Baytex Energy Corp.**
**Condensed Consolidated Interim Statements of Financial Position**
*(thousands of Canadian dollars) (unaudited)*

| | Notes | As at September 30, 2022 | As at December 31, 2021 |
|---|---|---|---|
| **ASSETS** | | | |
| Current assets | | | |
| Cash | | **$ 4,410** | $ — |
| Trade and other receivables | | **251,689** | 173,409 |
| Financial derivatives | 16 | **12,102** | 8,654 |
| | | **268,201** | 182,063 |
| Non-current assets | | | |
| Financial derivatives | 16 | **4,097** | — |
| Exploration and evaluation assets | 4 | **160,137** | 172,824 |
| Oil and gas properties | 5 | **4,415,957** | 4,464,371 |
| Other plant and equipment | | **6,725** | 7,121 |
| Lease assets | | **7,448** | 8,264 |
| Deferred income tax asset | 13 | **61,052** | — |
| | | **$ 4,923,617** | $ 4,834,643 |
| **LIABILITIES** | | | |
| Current liabilities | | | |
| Trade and other payables | | **$ 268,410** | $ 190,692 |
| Financial derivatives | 16 | **48,587** | 134,020 |
| Lease obligations | | **3,731** | 2,938 |
| Asset retirement obligations | 8 | **10,869** | 11,080 |
| | | **331,597** | 338,730 |
| Non-current liabilities | | | |
| Trade and other payables | | **2,990** | — |
| Credit facilities | 6 | **447,475** | 505,171 |
| Long-term notes | 7 | **639,679** | 874,527 |
| Lease obligations | | **3,507** | 4,827 |
| Asset retirement obligations | 8 | **543,773** | 732,603 |
| Deferred income tax liability | 13 | **231,147** | 167,456 |
| | | **2,200,168** | 2,623,314 |
| **SHAREHOLDERS' EQUITY** | | | |
| Shareholders' capital | 9 | **5,527,831** | 5,736,593 |
| Contributed surplus | | **83,782** | 13,559 |
| Accumulated other comprehensive income | | **779,964** | 632,103 |
| Deficit | | **(3,668,128)** | (4,170,926) |
| | | **2,723,449** | 2,211,329 |
| | | **$ 4,923,617** | $ 4,834,643 |

See accompanying notes to the condensed consolidated interim financial statements.

**Baytex Energy Corp.**
**Condensed Consolidated Interim Statements of Income and Comprehensive Income**
*(thousands of Canadian dollars, except per common share amounts and weighted average common shares) (unaudited)*

| | | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|---|
| | Notes | **2022** | 2021 | **2022** | 2021 |
| **Revenue, net of royalties** | | | | | |
| Petroleum and natural gas sales | 12 | **$ 712,065** | $ 488,736 | **$ 2,240,059** | $ 1,315,792 |
| Royalties | | **(146,994)** | (90,523) | **(441,273)** | (239,004) |
| | | **565,071** | 398,213 | **1,798,786** | 1,076,788 |
| **Expenses** | | | | | |
| Operating | | **110,139** | 84,196 | **318,331** | 247,645 |
| Transportation | | **12,771** | 7,818 | **33,744** | 24,092 |
| Blending and other | | **40,945** | 19,581 | **139,280** | 56,668 |
| General and administrative | | **12,003** | 9,980 | **35,325** | 29,323 |
| Exploration and evaluation | 4 | **6,566** | 6,766 | **17,346** | 10,718 |
| Depletion and depreciation | | **144,177** | 127,052 | **427,254** | 332,119 |
| Impairment reversal | 5 | **—** | — | **—** | (1,126,415) |
| Share-based compensation | 10 | **3,072** | 2,511 | **9,959** | 8,262 |
| Financing and interest | 14 | **25,753** | 29,028 | **77,074** | 83,832 |
| Financial derivatives (gain) loss | 16 | **(114,063)** | 62,846 | **191,838** | 293,105 |
| Foreign exchange loss | 15 | **38,905** | 7,466 | **52,269** | 2,405 |
| Gain on dispositions | | **(4,566)** | (2,112) | **(5,007)** | (6,092) |
| Other expense (income) | | **5,223** | (366) | **4,759** | (2,092) |
| | | **280,925** | 354,766 | **1,302,172** | (46,430) |
| **Net income before income taxes** | | **284,146** | 43,447 | **496,614** | 1,123,218 |
| **Income tax expense (recovery)** | 13 | | | | |
| Current income tax expense | | **703** | 486 | **2,753** | 894 |
| Deferred income tax expense (recovery) | | **18,475** | 10,248 | **(8,937)** | 71,963 |
| | | **19,178** | 10,734 | **(6,184)** | 72,857 |
| **Net income** | | **$ 264,968** | $ 32,713 | **$ 502,798** | $ 1,050,361 |
| **Other comprehensive income (loss)** | | | | | |
| Foreign currency translation adjustment | | **117,023** | 26,175 | **147,861** | 18,969 |
| **Comprehensive income** | | **$ 381,991** | $ 58,888 | **$ 650,659** | $ 1,069,330 |
| **Net income per common share** | 11 | | | | |
| Basic | | **$ 0.48** | $ 0.06 | **$ 0.89** | $ 1.86 |
| Diluted | | **$ 0.47** | $ 0.06 | **$ 0.89** | $ 1.84 |
| **Weighted average common shares (000's)** | 11 | | | | |
| Basic | | **553,409** | 564,211 | **561,931** | 563,492 |
| Diluted | | **559,174** | 571,647 | **567,662** | 570,179 |

See accompanying notes to the condensed consolidated interim financial statements.

**Baytex Energy Corp.**

**Condensed Consolidated Interim Statements of Changes in Equity**

*(thousands of Canadian dollars) (unaudited)*

| | Notes | Shareholders' capital | Contributed surplus | Accumulated other comprehensive income | Deficit | Total equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2020** | | $ 5,729,418 | $ 14,345 | $ 618,976 | $ (5,784,526) | **$ 578,213** |
| Vesting of share awards | | 7,175 | (7,175) | — | — | **—** |
| Share-based compensation | | — | 4,603 | — | — | **4,603** |
| Comprehensive income | | — | — | 18,969 | 1,050,361 | **1,069,330** |
| **Balance at September 30, 2021** | | $ 5,736,593 | $ 11,773 | $ 637,945 | $ (4,734,165) | **$ 1,652,146** |
| **Balance at December 31, 2021** | | $ 5,736,593 | $ 13,559 | $ 632,103 | $ (4,170,926) | **$ 2,211,329** |
| Vesting of share awards | 9 | 8,501 | (8,501) | — | — | **—** |
| Share-based compensation | 10 | — | 2,715 | — | — | **2,715** |
| Repurchase of common shares for cancellation | 9 | (217,263) | 76,009 | — | — | **(141,254)** |
| Comprehensive income | | — | — | 147,861 | 502,798 | **650,659** |
| **Balance at September 30, 2022** | | $ 5,527,831 | $ 83,782 | $ 779,964 | $ (3,668,128) | **$ 2,723,449** |

See accompanying notes to the condensed consolidated interim financial statements.

**Baytex Energy Corp.**
**Condensed Consolidated Interim Statements of Cash Flows**
*(thousands of Canadian dollars) (unaudited)*

| | | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|---|
| | Notes | **2022** | 2021 | **2022** | 2021 |
| **CASH PROVIDED BY (USED IN):** | | | | | |
| **Operating activities** | | | | | |
| Net income | | **$ 264,968** | $ 32,713 | **$ 502,798** | $ 1,050,361 |
| Adjustments for: | | | | | |
| Non-cash share-based compensation | 10 | **637** | 1,453 | **2,715** | 4,603 |
| Unrealized foreign exchange loss | 15 | **39,799** | 7,545 | **52,750** | 3,223 |
| Exploration and evaluation | 4 | **6,566** | 6,766 | **17,346** | 10,718 |
| Depletion and depreciation | | **144,177** | 127,052 | **427,254** | 332,119 |
| Impairment reversal | 5 | **—** | — | **—** | (1,126,415) |
| Non-cash financing and accretion | 14 | **5,979** | 6,235 | **16,399** | 13,082 |
| Non-cash other income | 8 | **(1,276)** | (444) | **(2,741)** | (2,108) |
| Unrealized financial derivatives (gain) loss | 16 | **(190,471)** | 8,941 | **(92,978)** | 179,408 |
| Gain on dispositions | | **(4,566)** | (2,112) | **(5,007)** | (6,092) |
| Deferred income tax expense (recovery) | 13 | **18,475** | 10,248 | **(8,937)** | 71,963 |
| Asset retirement obligations settled | 8 | **(4,599)** | (1,805) | **(10,608)** | (4,215) |
| Change in non-cash working capital | | **30,734** | (17,631) | **(29,560)** | (54,830) |
| | | **310,423** | 178,961 | **869,431** | 471,817 |
| **Financing activities** | | | | | |
| (Decrease) increase in credit facilities | | **(58,266)** | 53,430 | **(73,617)** | (107,230) |
| Debt issuance costs | | **(305)** | — | **(2,137)** | — |
| Payments on lease obligations | | **(668)** | (1,142) | **(2,881)** | (3,143) |
| Redemption of long-term notes | 7 | **(35,599)** | (139,861) | **(288,429)** | (146,648) |
| Repurchase of common shares | 9 | **(78,790)** | — | **(141,254)** | — |
| | | **(173,628)** | (87,573) | **(508,318)** | (257,021) |
| **Investing activities** | | | | | |
| Additions to exploration and evaluation assets | 4 | **—** | (89) | **(5,897)** | (733) |
| Additions to oil and gas properties | 5 | **(167,453)** | (94,146) | **(412,011)** | (238,575) |
| Additions to other plant and equipment | | **(148)** | (158) | **(782)** | (569) |
| Property acquisitions | | **—** | (89) | **(267)** | (114) |
| Proceeds from dispositions | | **25,460** | 701 | **25,501** | 947 |
| Change in non-cash working capital | | **9,756** | 1,018 | **36,753** | 24,248 |
| | | **(132,385)** | (92,763) | **(356,703)** | (214,796) |
| Change in cash | | **4,410** | (1,375) | **4,410** | — |
| Cash, beginning of period | | **—** | 1,375 | **—** | — |
| **Cash, end of period** | | **$ 4,410** | $ — | **$ 4,410** | $ — |
| **Supplementary information** | | | | | |
| Interest paid | | **$ 35,587** | $ 32,436 | **$ 77,116** | $ 80,037 |
| Income taxes paid | | **$ 1,906** | $ — | **$ 2,169** | $ — |

See accompanying notes to the condensed consolidated interim financial statements.

## 1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the state of Texas in the United States. The Company’s common shares are traded on the Toronto Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

## 2. BASIS OF PRESENTATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These condensed consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2021.

The consolidated financial statements were approved by the Board of Directors of Baytex on November 3, 2022.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

*The audited consolidated financial statements of the Company as at and for the year ended December 31, 2021 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.*

### Significant Accounting Policies

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2021 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of *Normal Course Issue Bid ("NCIB") Share Repurchases* as described below.

*Current Environment and Estimation Uncertainty*

Management makes judgements and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

During the nine months ended September 30, 2022, demand for oil and natural gas improved as the global economy continued to recover from the COVID-19 pandemic. Early in 2022, energy prices strengthened to multi-year highs due to heightened uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. Recent declines in global oil prices have been caused by concern over future demand caused by central bank actions to moderate inflation. The impact of these factors has been considered in management's estimates as at and for the period ended September 30, 2022.

*Normal Course Issuer Bid ("NCIB") Share Repurchases*

On May 2, 2022, Baytex announced the acceptance from the Toronto Stock Exchange ("TSX") for implementation of a NCIB under which Baytex is permitted to purchase for cancellation a specified number of common shares over a specified time frame. The shares repurchased and cancelled are accounted for as a reduction in Share Capital at historical cost, with any discount paid recorded to Contributed Surplus and any premium paid recorded to Retained Earnings. Total consideration paid includes any commissions or fees paid as part of the transaction.

## 3. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

| | Canada | | U.S. | | Corporate | | Consolidated | |
|---|---|---|---|---|---|---|---|---|
| **Three Months Ended September 30** | **2022** | 2021 | **2022** | 2021 | **2022** | 2021 | **2022** | 2021 |
| **Revenue, net of royalties** | | | | | | | | |
| Petroleum and natural gas sales | **$ 473,708** | $ 292,723 | **$ 238,357** | $ 196,013 | **$ —** | $ — | **$ 712,065** | $ 488,736 |
| Royalties | **(75,901)** | (32,679) | **(71,093)** | (57,844) | **—** | — | **(146,994)** | (90,523) |
| | **397,807** | 260,044 | **167,264** | 138,169 | **—** | — | **565,071** | 398,213 |
| **Expenses** | | | | | | | | |
| Operating | **83,141** | 63,301 | **26,998** | 20,895 | **—** | — | **110,139** | 84,196 |
| Transportation | **12,771** | 7,818 | **—** | — | **—** | — | **12,771** | 7,818 |
| Blending and other | **40,945** | 19,581 | **—** | — | **—** | — | **40,945** | 19,581 |
| General and administrative | **—** | — | **—** | — | **12,003** | 9,980 | **12,003** | 9,980 |
| Exploration and evaluation | **6,566** | 6,766 | **—** | — | **—** | — | **6,566** | 6,766 |
| Depletion and depreciation | **102,353** | 82,241 | **40,298** | 43,440 | **1,526** | 1,371 | **144,177** | 127,052 |
| Share-based compensation | **—** | — | **—** | — | **3,072** | 2,511 | **3,072** | 2,511 |
| Financing and interest | **—** | — | **—** | — | **25,753** | 29,028 | **25,753** | 29,028 |
| Financial derivatives (gain) loss | **—** | — | **—** | — | **(114,063)** | 62,846 | **(114,063)** | 62,846 |
| Foreign exchange loss | **—** | — | **—** | — | **38,905** | 7,466 | **38,905** | 7,466 |
| (Gain) loss on dispositions | **(4,566)** | (2,302) | **—** | 190 | **—** | — | **(4,566)** | (2,112) |
| Other (income) expense | **(1,276)** | (444) | **—** | — | **6,499** | 78 | **5,223** | (366) |
| | **239,934** | 176,961 | **67,296** | 64,525 | **(26,305)** | 113,280 | **280,925** | 354,766 |
| **Net income (loss) before income taxes** | **157,873** | 83,083 | **99,968** | 73,644 | **26,305** | (113,280) | **284,146** | 43,447 |
| **Income tax expense** | | | | | | | | |
| Current income tax expense | | | | | | | **703** | 486 |
| Deferred income tax expense | | | | | | | **18,475** | 10,248 |
| | | | | | | | **19,178** | 10,734 |
| **Net income (loss)** | **$ 157,873** | $ 83,083 | **$ 99,968** | $ 73,644 | **$ 26,305** | $ (113,280) | **$ 264,968** | $ 32,713 |
| Additions to exploration and evaluation assets | **—** | 89 | **—** | — | **—** | — | **—** | 89 |
| Additions to oil and gas properties | **117,150** | 75,410 | **50,303** | 18,736 | **—** | — | **167,453** | 94,146 |
| Property acquisitions | **—** | 89 | **—** | — | **—** | — | **—** | 89 |
| Proceeds from dispositions | **(25,460)** | (108) | **—** | (593) | **—** | — | **(25,460)** | (701) |

| Nine Months Ended September 30 | Canada 2022 | Canada 2021 | U.S. 2022 | U.S. 2021 | Corporate 2022 | Corporate 2021 | Consolidated 2022 | Consolidated 2021 |
|---|---|---|---|---|---|---|---|---|
| **Revenue, net of royalties** | | | | | | | | |
| Petroleum and natural gas sales | **$ 1,508,609** | $ 786,171 | **$ 731,450** | $ 529,621 | **$ —** | $ — | **$ 2,240,059** | $ 1,315,792 |
| Royalties | **(224,710)** | (83,536) | **(216,563)** | (155,468) | **—** | — | **(441,273)** | (239,004) |
| | **1,283,899** | 702,635 | **514,887** | 374,153 | **—** | — | **1,798,786** | 1,076,788 |
| **Expenses** | | | | | | | | |
| Operating | **244,152** | 186,455 | **74,179** | 61,190 | **—** | — | **318,331** | 247,645 |
| Transportation | **33,744** | 24,092 | **—** | — | **—** | — | **33,744** | 24,092 |
| Blending and other | **139,280** | 56,668 | **—** | — | **—** | — | **139,280** | 56,668 |
| General and administrative | **—** | — | **—** | — | **35,325** | 29,323 | **35,325** | 29,323 |
| Exploration and evaluation | **17,346** | 10,718 | **—** | — | **—** | — | **17,346** | 10,718 |
| Depletion and depreciation | **304,147** | 215,803 | **118,759** | 112,368 | **4,348** | 3,948 | **427,254** | 332,119 |
| Impairment reversal | **—** | (684,000) | **—** | (442,415) | **—** | — | **—** | (1,126,415) |
| Share-based compensation | **—** | — | **—** | — | **9,959** | 8,262 | **9,959** | 8,262 |
| Financing and interest | **—** | — | **—** | — | **77,074** | 83,832 | **77,074** | 83,832 |
| Financial derivatives loss | **—** | — | **—** | — | **191,838** | 293,105 | **191,838** | 293,105 |
| Foreign exchange loss | **—** | — | **—** | — | **52,269** | 2,405 | **52,269** | 2,405 |
| (Gain) loss on dispositions | **(5,007)** | (6,282) | **—** | 190 | **—** | — | **(5,007)** | (6,092) |
| Other (income) expense | **(2,741)** | (2,108) | **—** | — | **7,500** | 16 | **4,759** | (2,092) |
| | **730,921** | (198,654) | **192,938** | (268,667) | **378,313** | 420,891 | **1,302,172** | (46,430) |
| | **552,978** | 901,289 | **321,949** | 642,820 | **(378,313)** | (420,891) | **496,614** | 1,123,218 |
| **Income tax expense (recovery)** | | | | | | | | |
| Current income tax expense | | | | | | | **2,753** | 894 |
| Deferred income tax (recovery) expense | | | | | | | **(8,937)** | 71,963 |
| | | | | | | | **(6,184)** | 72,857 |
| **Net income (loss)** | **$ 552,978** | $ 901,289 | **$ 321,949** | $ 642,820 | **$ (378,313)** | $ (420,891) | **$ 502,798** | $ 1,050,361 |
| Additions to exploration and evaluation assets | **5,897** | 733 | **—** | — | **—** | — | **5,897** | 733 |
| Additions to oil and gas properties | **289,264** | 147,656 | **122,747** | 90,919 | **—** | — | **412,011** | 238,575 |
| Property acquisitions | **267** | 114 | **—** | — | **—** | — | **267** | 114 |
| Proceeds from dispositions | **(25,501)** | (354) | **—** | (593) | **—** | — | **(25,501)** | (947) |

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| Canadian assets | **$ 2,497,256** | $ 2,658,281 |
| U.S. assets | **2,395,989** | 2,152,323 |
| Corporate assets | **30,372** | 24,039 |
| **Total consolidated assets** | **$ 4,923,617** | $ 4,834,643 |

## 4. EXPLORATION AND EVALUATION ASSETS

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| **Balance, beginning of period** | **$ 172,824** | $ 191,865 |
| Capital expenditures | **5,897** | 3,298 |
| Property acquisitions | **—** | 1,100 |
| Divestitures | **(498)** | (166) |
| Property swaps | **—** | 408 |
| Exploration and evaluation expense | **(17,346)** | (15,212) |
| Transfer to oil and gas properties (note 5) | **(7,301)** | (7,727) |
| Foreign currency translation | **6,561** | (742) |
| **Balance, end of period** | **$ 160,137** | $ 172,824 |

At September 30, 2022 and December 31, 2021, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's cash generating units ("CGU").

## 5. OIL AND GAS PROPERTIES

| | Cost | Accumulated depletion | Net book value |
|---|---|---|---|
| **Balance, December 31, 2020** | **$ 11,423,676** | **$ (8,346,128)** | **$ 3,077,548** |
| Capital expenditures | 310,005 | — | 310,005 |
| Property acquisitions | 274 | — | 274 |
| Transfers from exploration and evaluation assets (note 4) | 7,727 | — | 7,727 |
| Change in asset retirement obligations (note 8) | (12,222) | — | (12,222) |
| Divestitures | (37,835) | 32,844 | (4,991) |
| Property swaps | (26,131) | 25,900 | (231) |
| Impairment reversal | — | 1,542,414 | 1,542,414 |
| Foreign currency translation | (31,977) | 34,765 | 2,788 |
| Depletion | — | (458,941) | (458,941) |
| **Balance, December 31, 2021** | **$ 11,633,517** | **$ (7,169,146)** | **$ 4,464,371** |
| Capital expenditures | 412,011 | — | 412,011 |
| Property acquisitions | 361 | — | 361 |
| Transfers from exploration and evaluation assets (note 4) | 7,301 | — | 7,301 |
| Change in asset retirement obligations (note 8) | (185,649) | — | (185,649) |
| Divestitures | (265,145) | 241,892 | (23,253) |
| Foreign currency translation | 352,730 | (189,009) | 163,721 |
| Depletion | — | (422,906) | (422,906) |
| **Balance, September 30, 2022** | **$ 11,955,126** | **$ (7,539,169)** | **$ 4,415,957** |

During the third quarter of 2022, Baytex completed a minor non-core property disposition in the Conventional CGU for proceeds of $25.5 million.

At September 30, 2022, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

**2021 Impairment Reversals**

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGUs due to the increase in forecasted commodity prices. The recoverable amount for each of our six CGUs exceeded their carrying amounts which resulted in an impairment reversal of $1.1 billion recorded at June 30, 2021. The recoverable amount for each CGU was based on its fair value less costs of disposal ("FVLCD") which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2020 which was adjusted by management for operations between December 31, 2020 and June 30, 2021. The after-tax discount rates applied to the cash flows were between 10% and 16%.

At December 31, 2021, we identified indicators of impairment reversal for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amount for three CGUs exceeded their carrying amounts which resulted in an impairment reversal of $416 million recorded at December 31, 2021. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2021. The after-tax discount rates applied to the cash flows were between 12% and 19%.

## 6. CREDIT FACILITIES

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| Credit facilities - U.S. dollar denominated (1) | $ 172,714 | $ 156,332 |
| Credit facilities - Canadian dollar denominated | 277,337 | 350,182 |
| Credit facilities - principal (2) | 450,051 | 506,514 |
| Unamortized debt issuance costs | (2,576) | (1,343) |
| Credit facilities | $ 447,475 | $ 505,171 |

*(1) U.S. dollar denominated credit facilities balance was US$126.1 million as at September 30, 2022 (December 31, 2021 - US$123.5 million).*
*(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2021 to September 30, 2022 is the result of net repayments of $73.6 million, partially offset by an increase in the reported amount of U.S. denominated debt of $17.2 million due to foreign exchange.*

At September 30, 2022, Baytex had US$850 million of revolving credit facilities (the "Credit Facilities"). On April 1, 2022, Baytex amended its Credit Facilities to increase the revolving credit facility to US$850 million and extend maturity from April 1, 2024 to April 1, 2026. The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. There were no changes to the financial covenants as a result of the amendments.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended by Baytex. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 3.1% for the nine months ended September 30, 2022 (2.2% for nine months ended September 30, 2021).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at September 30, 2022.

| Covenant Description | Position as at September 30, 2022 | Covenant |
|---|---|---|
| Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio) | 0.4:1:0 | 3.5:1.0 |
| Interest Coverage (3) (Minimum Ratio) | 14.8:1.0 | 2.0:1.0 |

*(1) "Senior Secured Debt" is calculated in accordance with the Credit Facility agreements and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. As at September 30, 2022, the Company's Senior Secured Debt totaled $450.1 million of principal amounts outstanding.*
*(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2022 was $1.2 billion.*
*(3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expense for the twelve months ended September 30, 2022 was $81.8 million.*

On July 25, 2022 Baytex entered into a $20 million uncommitted unsecured demand revolving letter of credit facility (the "LC Facility"). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities. As at September 30, 2022, Baytex had $15.8 million of outstanding letters of credit under the LC Facility.

## 7. LONG-TERM NOTES

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| 5.625% notes due June 1, 2024 (1) | $ — | $ 253,120 |
| 8.75% notes due April 1, 2027 (2) | 648,207 | 632,800 |
| Total long-term notes - principal (3) | 648,207 | 885,920 |
| Unamortized debt issuance costs | (8,528) | (11,393) |
| Total long-term notes - net of unamortized debt issuance costs | $ 639,679 | $ 874,527 |

*(1) The U.S. dollar denominated principal outstanding of the 5.625% notes was nil as at September 30, 2022 (December 31, 2021 - US$200.0 million).*

*(2) The U.S. dollar denominated principal outstanding of the 8.75% notes was US$473.2 million as at September 30, 2022 (December 31, 2021 - US$500.0 million).*

*(3) The decrease in the principal amount of long-term notes outstanding from December 31, 2021 to September 30, 2022 is the result of principal repayments of $288.1 million partially offset by changes in the reported amount of U.S. denominated debt of $50.4 million.*

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for debt incurrence and restricted payments.

During the three months ended September 30, 2022, Baytex repurchased and cancelled US$26.8 million principal of the 8.75% Notes and recorded early redemption expense of $0.3 million.

On June 1, 2022, Baytex completed the early redemption of the US$200.0 million principal amount of the 5.625% Notes due in 2024 at par plus accrued interest and recorded a decrease to unamortized debt issuance costs of $1.7 million.

## 8. ASSET RETIREMENT OBLIGATIONS

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| **Balance, beginning of period** | $ 743,683 | $ 760,383 |
| Liabilities incurred | 13,855 | 14,845 |
| Liabilities settled | (10,608) | (6,662) |
| Liabilities acquired from property acquisitions | 138 | 249 |
| Liabilities divested | (3,301) | (3,161) |
| Property swaps | — | (4,113) |
| Accretion (note 14) | 11,403 | 12,381 |
| Government grants (1) | (2,741) | (2,857) |
| Change in estimate | 2,215 | (9,686) |
| Changes in discount rates and inflation rates (2) | (201,719) | (17,381) |
| Foreign currency translation | 1,717 | (315) |
| **Balance, end of period** | $ 554,642 | $ 743,683 |
| Less current portion of asset retirement obligations | 10,869 | 11,080 |
| Non-current portion of asset retirement obligations | $ 543,773 | $ 732,603 |

*(1) During the nine months ended September 30, 2022, Baytex recognized $2.7 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($2.9 million for the year ended December 31, 2021).*

*(2) The discount and inflation rates at September 30, 2022 were 3.1% and 1.7%, respectively, compared to 1.7% and 1.8% at December 31, 2021.*

## 9. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. At September 30, 2022, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

During 2022, the TSX accepted Baytex's notice of intention to implement a NCIB. Under the terms of the NCIB, the Company may purchase for cancellation up to 56.3 million common shares over the 12-month period commencing May 9, 2022. The number of shares authorized for repurchase represents 10% of the Company's public float as at April 29, 2022. Purchases are made on the open market at prices prevailing at the time of the transaction.

| | Number of Common Shares (000s) | | Amount |
|---|---|---|---|
| **Balance, December 31, 2020** | **561,227** | **$** | **5,729,418** |
| Vesting of share awards | 2,986 | | 7,175 |
| **Balance, December 31, 2021** | **564,213** | **$** | **5,736,593** |
| Vesting of share awards | 5,035 | | 8,501 |
| Common shares repurchased and cancelled | (21,633) | | (217,263) |
| **Balance, September 30, 2022** | **547,615** | **$** | **5,527,831** |

During the nine months ended September 30, 2022, Baytex repurchased and cancelled 21.6 million common shares at an average price of $6.53 per share for total consideration of $141.3 million. The total consideration paid includes commissions and fees and is recorded as a reduction to Shareholders' Equity.

## 10. SHARE-BASED COMPENSATION PLAN

For the three and nine months ended September 30, 2022 the Company recorded total compensation expense related to the share awards of $3.1 million and $10.0 million respectively ($2.5 million and $8.3 million for the three and nine months ended September 30, 2021). Included in compensation expense related to share awards for the three and nine months ended September 30, 2022 is $2.4 million and $7.3 million of cash compensation expense related to the incentive award plan, deferred share unit plan and the associated equity total return swaps ($1.1 million and $3.7 million for the three and nine months ended September 30, 2021).

### Share Award Incentive Plan

Baytex has a share award plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex or the equivalent cash value at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares on vesting; the number of common shares issued is determined by a multiplier. The multiplier, which ranges between zero and two, is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The restricted awards and performance awards vest in equal tranches on the first, second and third anniversaries of the grant date.

The weighted average fair value of share awards granted during the nine months ended September 30, 2022 was $5.68 per restricted and performance award ($1.30 for the nine months ended September 30, 2021).

The number of share awards outstanding is detailed below:

| *(000s)* | Number of restricted awards | Number of performance awards | Total number of share awards |
|---|---|---|---|
| **Balance, December 31, 2020** | **4,122** | **4,088** | **8,210** |
| Granted | — | 4,067 | 4,067 |
| Added by performance factor | — | 669 | 669 |
| Vested | (1,861) | (1,152) | (3,013) |
| Forfeited | (168) | (291) | (459) |
| **Balance, December 31, 2021** | **2,093** | **7,381** | **9,474** |
| Granted | — | 1,111 | 1,111 |
| Vested | (1,377) | (3,630) | (5,007) |
| Forfeited | (22) | (26) | (48) |
| **Balance, September 30, 2022** | **694** | **4,836** | **5,530** |

**Incentive Award Plan**

Baytex has an incentive award plan (the "Incentive Award" plan) whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

During the nine months ended September 30, 2022, Baytex granted 1.4 million awards under the Incentive Award plan at a fair value of $5.68 per award (5.0 million awards at $1.32 per award for the nine months ended September 30, 2021). At September 30, 2022 there were 5.2 million awards outstanding under the Incentive Award plan (6.4 million awards outstanding at December 31, 2021).

**Deferred Share Unit Plan**

Baytex has a deferred share unit plan (the "DSU" plan) whereby each non-employee Director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share on the date on which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in trade and other payables.

During the nine months ended September 30, 2022, Baytex granted 0.2 million awards under the DSU plan at a fair value of $5.68 per award (0.9 million awards at $1.29 per award for the nine months ended September 30, 2021). At September 30, 2022, there were 1.0 million awards outstanding under the DSU plan.

**Equity Total Return Swaps**

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix a portion of the aggregate cost of the cash-settled plans including the Incentive Award plan, the DSU plan and the Share Award Incentive Plan, at the fair value determined on the grant date. The carrying value of the Company's financial derivatives includes the fair value of the equity total return swap which was an asset of $4.6 million on September 30, 2022 (December 31, 2021 - asset of $6.5 million). At September 30, 2022, an asset of $15.1 million associated with the equity return swap is included in accounts payable as it relates to the settlement of cash compensation payable (December 31, 2021 - an asset of $10.7 million).

## 11. NET INCOME PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

| Three Months Ended September 30 | | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Net income** | **Weighted average common shares (000s)** | **Net income per share** | Net income | Weighted average common shares (000s) | Net income per share |
| Net income - basic | **$ 264,968** | **553,409** | **$ 0.48** | $ 32,713 | 564,211 | $ 0.06 |
| Dilutive effect of share awards | **—** | **5,765** | **—** | — | 7,436 | — |
| Net income - diluted | **$ 264,968** | **559,174** | **$ 0.47** | $ 32,713 | 571,647 | $ 0.06 |

| Nine Months Ended September 30 | | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Net income** | **Weighted average common shares (000s)** | **Net income per share** | **Net income** | Weighted average common shares (000s) | Net income per share |
| Net income - basic | **$ 502,798** | **561,931** | **$ 0.89** | $ 1,050,361 | 563,492 | $ 1.86 |
| Dilutive effect of share awards | **—** | **5,731** | **—** | — | 6,687 | — |
| Net income - diluted | **$ 502,798** | **567,662** | **$ 0.89** | $ 1,050,361 | 570,179 | $ 1.84 |

For the three and nine months ended September 30, 2022 and September 30, 2021 no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

## 12. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

| | Three Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Light oil and condensate | **$ 175,447** | **$ 188,521** | **$ 363,968** | $ 124,930 | $ 154,511 | $ 279,441 |
| Heavy oil | **267,958** | **—** | **267,958** | 146,468 | — | 146,468 |
| NGL | **7,929** | **22,627** | **30,556** | 4,177 | 22,932 | 27,109 |
| Natural gas sales | **22,374** | **27,209** | **49,583** | 17,148 | 18,570 | 35,718 |
| Total petroleum and natural gas sales | **$ 473,708** | **$ 238,357** | **$ 712,065** | $ 292,723 | $ 196,013 | $ 488,736 |

| | Nine Months Ended September 30 | | | | | |
|---|---|---|---|---|---|---|
| | **2022** | | | 2021 | | |
| | **Canada** | **U.S.** | **Total** | Canada | U.S. | Total |
| Light oil and condensate | **$ 548,588** | **$ 591,946** | **$ 1,140,534** | $ 342,744 | $ 418,498 | $ 761,242 |
| Heavy oil | **858,497** | **—** | **858,497** | 385,288 | — | 385,288 |
| NGL | **23,701** | **69,529** | **93,230** | 12,327 | 52,870 | 65,197 |
| Natural gas sales | **77,823** | **69,975** | **147,798** | 45,812 | 58,253 | 104,065 |
| Total petroleum and natural gas sales | **$ 1,508,609** | **$ 731,450** | **$ 2,240,059** | $ 786,171 | $ 529,621 | $ 1,315,792 |

Included in accounts receivable at September 30, 2022 is $223.0 million of accrued production revenue related to delivered volumes (December 31, 2021 - $154.0 million).

## 13. INCOME TAXES

The provision for income taxes has been computed as follows:

| | Nine Months Ended September 30 | |
|---|---|---|
| | **2022** | 2021 |
| Net income before income taxes | **$ 496,614** | $ 1,123,218 |
| Expected income taxes at the statutory rate of 24.80% (2021 – 25.12%) | **123,160** | 282,152 |
| Increase (decrease) in income taxes resulting from: | | |
| Effect of foreign exchange | **5,917** | (292) |
| Effect of rate adjustments for foreign jurisdictions | **(21,237)** | (19,751) |
| Effect of change in deferred tax benefit not recognized | **(72,297)** | (191,611) |
| Effect of internal debt restructuring | **(44,793)** | — |
| Adjustments, assessments and other | **3,066** | 2,359 |
| Income tax (recovery) expense | **$ (6,184)** | $ 72,857 |

At September 30, 2022, a deferred tax asset of $72.0 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2021 - $145.6 million).

As disclosed in the 2021 annual financial statements, in June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the “CRA”) that denied $591.0 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

## 14. FINANCING AND INTEREST

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2022** | 2021 | **2022** | 2021 |
| Interest on Credit Facilities | **$ 5,788** | $ 3,256 | **$ 12,897** | $ 9,842 |
| Interest on long-term notes | **13,935** | 19,481 | **47,635** | 60,734 |
| Interest on lease obligations | **51** | 56 | **143** | 174 |
| Cash Interest | **$ 19,774** | $ 22,793 | **$ 60,675** | $ 70,750 |
| Amortization of debt issue costs | **1,242** | 1,733 | **4,671** | 3,272 |
| Accretion on asset retirement obligations (note 8) | **4,412** | 3,273 | **11,403** | 8,938 |
| Early redemption expense (note 7) | **325** | 1,229 | **325** | 872 |
| Financing and interest | **$ 25,753** | $ 29,028 | **$ 77,074** | $ 83,832 |

## 15. FOREIGN EXCHANGE

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2022** | 2021 | **2022** | 2021 |
| Unrealized foreign exchange (gain) loss - intercompany notes (1) | **$ —** | $ (25,909) | **$ (2,674)** | $ 411 |
| Unrealized foreign exchange loss - long-term notes & Credit Facilities | **39,799** | 33,454 | **55,424** | 2,812 |
| Realized foreign exchange gain | **(894)** | (79) | **(481)** | (818) |
| Foreign exchange loss | **$ 38,905** | $ 7,466 | **$ 52,269** | $ 2,405 |

*(1) Baytex had a series of intercompany notes totaling US$601.0 million outstanding at December 31, 2021 that were issued from a Canadian functional currency subsidiary to a U.S. functional currency subsidiary. These notes were eliminated upon consolidation within the Statement of Financial Position and were revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian functional currency subsidiary were recognized in unrealized foreign exchange gain or loss whereas those within the U.S. functional currency subsidiary were recognized in other comprehensive income. In January 2022 the intercompany notes were transferred from the Canadian functional currency subsidiary to another U.S. functional currency subsidiary. As a result, foreign exchange gains and losses incurred on these notes after the transfer are recognized in other comprehensive income.*

## 16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, Credit Facilities, and long-term notes. The fair value of trade and other receivables and trade and other payables approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the condensed consolidated statements of financial position are classified into the following categories:

| | **September 30, 2022** | | December 31, 2021 | | |
|---|---|---|---|---|---|
| | **Carrying value** | **Fair value** | Carrying value | Fair value | Fair Value Measurement Hierarchy |
| **Financial Assets** | | | | | |
| *Fair value through profit and loss* | | | | | |
| Financial derivatives | **$ 16,199** | **$ 16,199** | $ 8,654 | $ 8,654 | Level 2 |
| Total | **$ 16,199** | **$ 16,199** | $ 8,654 | $ 8,654 | |
| *Amortized cost* | | | | | |
| Cash | **$ 4,410** | **$ 4,410** | $ — | $ — | — |
| Trade and other receivables | **251,689** | **251,689** | 173,409 | 173,409 | — |
| Total | **$ 256,099** | **$ 256,099** | $ 173,409 | $ 173,409 | |
| **Financial Liabilities** | | | | | |
| *Fair value through profit and loss* | | | | | |
| Financial derivatives | **$ (48,587)** | **$ (48,587)** | $ (134,020) | $ (134,020) | Level 2 |
| Total | **$ (48,587)** | **$ (48,587)** | $ (134,020) | $ (134,020) | |
| *Amortized cost* | | | | | |
| Trade and other payables | **$ (271,400)** | **$ (271,400)** | $ (190,692) | $ (190,692) | — |
| Credit Facilities | **(447,475)** | **(450,051)** | (505,171) | (506,514) | — |
| Long-term notes | **(639,679)** | **(652,471)** | (874,527) | (917,889) | Level 1 |
| Total | **$ (1,358,554)** | **$ (1,373,922)** | $ (1,570,390) | $ (1,615,095) | |

There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 2022 and 2021.

### Foreign Currency Risk

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

| | Assets | | Liabilities | |
|---|---|---|---|---|
| | **September 30, 2022** | December 31, 2021 | **September 30, 2022** | December 31, 2021 |
| U.S. dollar denominated | **US$7,844** | US$602,503 | **US$539,995** | US$829,934 |

**Commodity Price Risk**

*Financial Derivative Contracts*

Baytex had the following financial derivative contracts outstanding as of November 3, 2022:

| | Remaining Period | Volume | Price/Unit (1) | Index |
|---|---|---|---|---|
| **Oil** | | | | |
| Basis Swap | Oct 2022 to Dec 2022 | 12,000 bbl/d | WTI less US$12.40/bbl | WCS |
| Basis Swap | Oct 2022 to Dec 2022 | 6,750 bbl/d | WTI less US$3.73/bbl | MSW |
| Fixed Sell | Oct 2022 to Dec 2022 | 10,000 bbl/d | US$53.50/bbl | WTI |
| 3-way option (2) | Oct 2022 to Dec 2022 | 1,500 bbl/d | US$40.00/US$50.00/US$58.10 | WTI |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,000 bbl/d | US$46.00/US$56.00/US$66.72 | WTI |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 bbl/d | US$47.00/US$57.00/US$67.00 | WTI |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 bbl/d | US$50.00/US$60.00/US$70.00 | WTI |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,000 bbl/d | US$53.00/US$63.50/US$72.90 | WTI |
| 3-way option (2) | Jan 2023 to Dec 2023 | 2,000 bbl/d | US$55.00/US$66.00/US$84.00 | WTI |
| 3-way option (2) | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$60.00/US$75.00/US$91.54 | WTI |
| 3-way option (2) | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$65.00/US$85.00/US$100.00 | WTI |
| 3-way option (2) | Jan 2023 to Dec 2023 | 2,500 bbl/d | US$65.00/US$85.00/US$106.50 | WTI |
| **Natural Gas** | | | | |
| Fixed Sell | Oct 2022 to Dec 2022 | 5,000 GJ/d | $2.53/GJ | AECO 7A |
| Fixed Sell | Oct 2022 to Dec 2022 | 14,250 GJ/d | $2.84/GJ | AECO 5A |
| Fixed Sell | Oct 2022 to Dec 2022 | 1,000 mmbtu/d | US$2.94/mmbtu | NYMEX |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.25/US$2.75/US$3.06 | NYMEX |
| 3-way option (2) | Oct 2022 to Dec 2022 | 1,500 mmbtu/d | US$2.60/US$2.91/US$3.56 | NYMEX |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.60/US$3.00/US$3.83 | NYMEX |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$2.65/US$2.90/US$3.40 | NYMEX |
| 3-way option (2) | Oct 2022 to Dec 2022 | 2,500 mmbtu/d | US$3.00/US$3.75/US$4.40 | NYMEX |

(1) *Based on the weighted average price per unit for the period.*
(2) *Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$50.00/US$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.*

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2022** | 2021 | **2022** | 2021 |
| Realized financial derivatives loss | **$ 76,408** | $ 53,905 | **$ 284,816** | $ 113,697 |
| Unrealized financial derivatives (gain) loss | **(190,471)** | 8,941 | **(92,978)** | 179,408 |
| Financial derivatives (gain) loss | **$ (114,063)** | $ 62,846 | **$ 191,838** | $ 293,105 |

## 17. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At September 30, 2022, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of Adjusted Funds Flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

### Net Debt

The Company uses net debt to monitor it's current financial position and to evaluate existing sources of liquidity. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Baytex also uses a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor the Company's existing capital structure and future liquidity requirements.

The following table reconciles Net Debt to amounts disclosed in the primary financial statements.

| | September 30, 2022 | December 31, 2021 |
|---|---|---|
| Credit Facilities | $ 447,475 | $ 505,171 |
| Unamortized debt issuance costs - Credit Facilities (note 6) | 2,576 | 1,343 |
| Long-term notes | 639,679 | 874,527 |
| Unamortized debt issuance costs - Long-term notes (note 7) | 8,528 | 11,393 |
| Trade and other payables | 271,400 | 190,692 |
| Cash | (4,410) | — |
| Trade and other receivables | (251,689) | (173,409) |
| Net Debt | $ 1,113,559 | $ 1,409,717 |
| Net Debt to Adjusted Funds Flow | 1.0 | 1.9 |

### Adjusted Funds Flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period.

Adjusted Funds Flow is reconciled to amounts disclosed in the primary financial statements in the following table.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | 2022 | 2021 | 2022 | 2021 |
| Cash flows from operating activities | $ 310,423 | $ 178,961 | $ 869,431 | $ 471,817 |
| Change in non-cash working capital | (30,734) | 17,631 | 29,560 | 54,830 |
| Asset retirement obligations settled | 4,599 | 1,805 | 10,608 | 4,215 |
| Adjusted Funds Flow | $ 284,288 | $ 198,397 | $ 909,599 | $ 530,862 |

# CORPORATE INFORMATION

## BOARD OF DIRECTORS

**Mark R. Bly**
Chairman of the Board

**Edward D. LaFehr**
Director

**Trudy M. Curran** [2,4]
Director

**Don G. Hrap** [1,3]
Director

**Jennifer A. Maki** [1,2]
Director

**Gregory K. Melchin** [1,4]
Director

**David L. Pearce** [2,3]
Director

**Steve D.L. Reynish** [3,4]
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves and Sustainability Committee
(4) Member of the Nominating and Governance Committee

## OFFICERS

**Edward D. LaFehr**
President and
Chief Executive Officer

**Rodney D. Gray**
Executive Vice President
and Chief Financial Officer

**Chad E. Lundberg**
Chief Operating and
Sustainability Officer

**Kendall D. Arthur**
Vice President, Heavy Oil

**Brian G. Ector**
Vice President, Capital Markets

**Nicole M. Frechette**
Vice President, Light Oil

**Chad L. Kalmakoff**
Vice President, Finance

**Scott Lovett**
Vice President,
Corporate Development

**James R. Maclean**
Vice President, General Counsel
and Corporate Secretary

## AUDITORS

KPMG LLP

## RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

## TRANSFER AGENT

Odyssey Trust Company

## EXCHANGE LISTINGS

Toronto Stock Exchange
Symbol: **BTE**

## HEAD OFFICE

**Baytex Energy Corp.**
Centennial Place, East Tower
2800, 520 - 3rd Avenue SW
Calgary, Alberta T2P 0R3

**Toll-free** 1.800.524.5521
**T** 587.952.3000
**F** 587.952.3001

**www.baytexenergy.com**

Design: ARTHUR / HUNTER

Printing: Merrill Corporation

BAYTEX