MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2020 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2020 and 2019. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is February 24, 2021.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual owns a diversified asset portfolio, including liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, heavy crude oil and shallow conventional natural gas in Eastern Alberta, and undeveloped bitumen leases in Northern Alberta. Additional information on Perpetual, including the most recently filed Annual Information Form ("AIF"), can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

ADVISORIES

NON-GAAP MEASURES: The terms "adjusted funds flow", "adjusted funds flow per share", "adjusted funds flow per boe", "available liquidity", "cash costs", "net working capital deficiency", "net debt", "net bank debt", "net debt to adjusted funds flow ratio", "operating netback", "realized revenue", and "enterprise value" used in this MD&A are not recognized under GAAP. Management believes that in addition to net income (loss) and net cash flows from (used in) operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from (used in) operating activities determined in accordance with GAAP as an indication of Perpetual's performance, and may not be comparable with the calculation of similar measurements by other entities.

Adjusted funds flow: Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. The Company has added back non-cash oil and natural gas revenue in-kind, equal to retained East Edson royalty obligation payments taken in-kind, to present the equivalent amount of cash revenue generated. The Company has also deducted payments of the gas over bitumen royalty financing from adjusted funds flow to present these payments net of gas over bitumen royalty credits received. These payments are indexed to gas over bitumen royalty credits and are recorded as a reduction to the Corporation's gas over bitumen royalty financing obligation in accordance with IFRS. Additionally, the Company has excluded payments of restructuring costs associated with employee downsizing costs, which management considers to not be related to cash flow from (used in) operating activities. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, and meet its financial obligations.

Adjusted funds flow per share is calculated using the weighted average number of shares outstanding used in calculating net income (loss) per share. Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS.

Adjusted funds flow per boe is calculated as adjusted funds flow divided by total production sold in the period.

The following table reconciles net cash flows from (used in) operating activities to adjusted funds flow:

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except per share and per boe amounts*)	**2020**	2019	**2020**	2019
Net cash flows from (used in) operating activities	**(1,104)**	(1,290)	**(9,533)**	17,806
Change in non-cash working capital	**1,479**	705	**(1,015)**	(4,602)
Decommissioning obligations settled	**95**	540	**210**	1,733
Oil and natural gas revenue in-kind	**917**	–	**2,319**	–
Payments of gas over bitumen royalty financing	**(197)**	(225)	**(704)**	(1,013)
Payments of restructuring costs	**50**	610	**936**	610
Adjusted funds flow	**1,240**	340	**(7,787)**	14,534
Adjusted funds flow per share	**0.02**	0.01	**(0.13)**	0.24
Adjusted funds flow per boe	**2.85**	0.46	**(4.25)**	4.43

Available Liquidity: Available Liquidity is defined as Perpetual's reserve-based credit facility (the "Credit Facility") borrowing limit (the "Borrowing Limit"), less borrowings and letters of credit issued under the Credit Facility. Management uses available liquidity to assess the ability of the Company to finance capital expenditures and expenditures on decommissioning obligations, and to meet its financial obligations.

Cash costs: Cash costs are comprised of royalties, production and operating, transportation, general and administrative, and cash finance expense. Cash costs per boe is calculated by dividing cash costs by total production sold in the period. Management believes that cash costs assist management and investors in assessing Perpetual's efficiency and overall cost structure.

($ thousands, except per boe amounts)	Three months ended December 31, 2020	2019	Years ended December 31, 2020	2019
Royalties	**1,831**	3,383	**6,571**	11,260
Production and operating	**3,014**	3,839	**11,634**	18,332
Transportation	**804**	1,551	**3,617**	6,258
General and administrative	**1,994**	2,406	**7,870**	11,660
Cash finance expense	**155**	2,376	**6,587**	9,280
Cash costs	**7,798**	13,555	**36,279**	56,790
Cash costs per boe	**17.92**	18.44	**19.78**	17.31

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue, and realized natural gas liquids ("NGL") revenue which includes realized gains (losses) on financial natural gas, crude oil, NGL, and foreign exchange contracts. Realized revenue is used by management to calculate the Corporation's net realized commodity prices, taking into account the monthly settlements of financial crude oil and natural gas forward sales, collars, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices and foreign exchange rates. Any related realized gains or losses are considered part of the Corporation's realized price.

Operating netback: Operating netback is calculated by deducting royalties, production and operating expenses, and transportation costs from realized revenue. Operating netback is also calculated on a per boe basis using production sold in the period. Operating netback on a per boe basis can vary significantly for each of the Company's operating areas. Perpetual considers operating netback to be an important performance measure as it demonstrates its profitability relative to current commodity prices.

Net working capital deficiency: Net working capital deficiency includes total current assets and current liabilities excluding short-term derivative assets and liabilities related to the Corporation's risk management activities, Tourmaline Oil Corp. ("TOU") share investment, TOU share margin demand loan, revolving bank debt, second lien term loan (the "Term Loan"), current portion of royalty obligations, current portion of lease liabilities, and current portion of provisions.

Net bank debt, net debt, and net debt to adjusted funds flow ratio: Net bank debt is measured as current and long-term revolving bank debt including net working capital deficiency. Net debt includes the carrying value of net bank debt, the principal amount of the Term Loan, the principal amount of the TOU share margin demand loan and the principal amount of senior notes, reduced for the mark-to-market value of the TOU share investment. Net debt, net bank debt, and net debt to adjusted funds flow ratios are used by management to assess the Corporation's overall debt position and borrowing capacity. Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

Enterprise value: Enterprise value is equal to net debt plus the market value of issued equity, and is used by management to analyze leverage.

VOLUME CONVERSIONS: Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A. Refer to the "Production" section of this MD&A for details of constituent product components that comprise Perpetual's boe production.

FOURTH QUARTER 2020 HIGHLIGHTS

Fourth quarter production averaged 4,730 boe/d, down 41% from the comparative period of 2019 (Q4 2019 – 7,991 boe/d). The decrease in production was due to the sale of a 50% working interest in the East Edson property in West Central Alberta to a third-party (the "Purchaser") for consideration including a cash payment of $35 million and the carried interest funding of the drill, complete and tie-in costs for an eight well drilling program (the "East Edson Transaction"). The closing of the East Edson Transaction on April 1, 2020 reduced West Central production by 3,220 boe/d when compared to the fourth quarter of 2019. Compared to the third quarter of 2020, total production increased by 13% or 542 boe/d, as production from the first five (2.5 net) East Edson carried interest wells is now online. In addition, the Company continued to reactivate heavy crude oil production as oil prices recover and stabilize. As of December 31, 2020, Perpetual had restarted all heavy crude oil production with the exception of approximately 185 bbl/d of higher cost production from certain wells at Mannville. Drilling of two (1.0 net) additional East Edson carried interest wells commenced in late January 2021 and are forecast to be on production by the end of March 2021. The final carried interest well is expected to be drilled and on production in the third quarter of 2021.

Realized revenue was $21.73/boe in the fourth quarter of 2020, 11% higher than the comparative period of 2019 (Q4 2019 – $19.50/boe). The increase was due primarily to the 20% improvement in Perpetual's realized oil price to $52.60/bbl, bolstered by financial hedging gains of $2.2 million ($18.92/boe). Compared to the prior year period, realized natural gas prices of $1.46/Mcf were 27% lower, due to realized hedging losses on locked-in AECO-NYMEX basis differential contracts of $2.6 million ($1.46/Mcf) despite the 6% increase in both NYMEX and AECO reference prices over the same period. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under its market diversification contract by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized gain on derivatives of $0.5 million ($1.15/boe) and increased the Company's realized natural gas price by $0.28/Mcf in the fourth quarter of 2020. Compared to the third quarter of 2020, realized revenue of $21.73/boe was up 21% (Q3 2020 – $17.93/boe), reflecting the 13% quarter-over-quarter increase in production combined with higher realized natural gas and NGL prices, partially offset by lower realized heavy crude oil prices.

Cash costs were down 3% on a unit-of-production basis to $17.92/boe (Q4 2019 - $18.44/boe). On an absolute dollar basis, cash costs were $7.8 million, 42% lower than the prior year period (Q4 2019 – $13.6 million) due to the East Edson Transaction, the reduction in work hours and corresponding employee compensation to 80% effective April 1, 2020, and payments received from the Canada Emergency Wage Subsidy

("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $0.3 million. In addition, the semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's Term Loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021.

Net income for the fourth quarter of 2020 was $14.4 million ($0.24/share), up $46.9 million from the prior year period (Q4 2019 – net loss of $32.5 million and $0.54/share). The increase was due primarily to the non-cash impairment reversal of $18.0 million recognized in the fourth quarter of 2020, compared to an impairment charge of $24.5 million in the fourth quarter of 2019. In addition, the change in fair value of derivatives contributed $0.4 million to net income in the fourth quarter of 2020, $5.3 million higher than the prior year period (Q4 2019 – loss of $4.9 million).

Net cash flows used in operating activities were $1.1 million, comparable to the prior year period of $1.3 million. Changes in non-cash working capital reduced operating cash flows by $1.5 million in the fourth quarter of 2020 compared to a reduction of $0.7 million in the comparative period of 2019. Excluding changes in non-cash working capital, net cash flows from operating activities were $0.4 million, an increase of $1.0 million from the prior year period, due primarily to the deferral of $1.8 million of Term Loan interest, partially offset by the 41% decrease in production.

Adjusted funds flow in the fourth quarter of 2020 was $1.2 million ($0.02/share), $0.9 million higher than the prior year period (Q4 2019 – $0.3 million). The increase was due to the same factors that drove higher cash flows from operating activities before changes in non-cash working capital. Compared to the third quarter of 2020, adjusted funds flow improved by $3.3 million, due to the deferral of $1.8 million of Term Loan interest, combined with the 13% increase in production and significantly higher realized natural gas prices of $1.46/Mcf (Q3 2020 – $0.06/Mcf).

2020 ANNUAL HIGHLIGHTS

Exploration and development spending in 2020 was $6.0 million, down 54% from the prior year (2019 – $12.9 million). Capital investment was focused on the Clearwater play in Eastern Alberta, where total spending of $5.5 million included costs to drill, complete and tie-in four (4.0 net) heavy crude oil wells in the Ukalta area. The program successfully demonstrated enhanced capital efficiency and performance, de-risked additional development drilling inventory, and resulted in finding and development costs ("F&D") of $9.26/boe (2019 – $17.27/boe) on a proved and probable basis, including changes in future development capital ("FDC"). The Clearwater drilling program, combined with better than forecast well performance and farm-in arrangements, contributed to a year-over-year increase in Clearwater proved plus probable reserves of 2.7 million bbls, representing 10% of total Company reserves at December 31, 2020 (2019 – 1%).

In accordance with the terms of the East Edson Transaction, the Purchaser drilled, completed and tied-in five (2.5 net) horizontal Wilrich carried interest wells during the year at the 50% owned East Edson property, with the next two (1.0 net) wells forecast to be on production by the end of March 2021. The final carried interest well is scheduled to be drilled, completed and tied-in during the third quarter of 2021. The East Edson development plan has been revised to reflect increased well spacing, longer extended-reach wells, and reduced capital costs per well related to the Purchaser's scale of operations as demonstrated by the execution of the 2020 carried interest drilling program. After giving effect to the East Edson Transaction, East Edson FDC decreased by 63% or $102.9 million on a proved plus probable basis, while proved reserves have increased by 8% from prior year levels.

Production in 2020 averaged 5,012 boe/d (29% heavy crude oil and NGL), a decrease of 44% from 8,988 boe/d (22% heavy crude oil and NGL) in 2019. The decrease in production was due primarily to the closing of the East Edson Transaction, combined with the temporary shut-in of heavy crude oil production throughout the second quarter in response to the abrupt drop in oil prices experienced due to local and global supply and demand imbalances and the COVID-19 pandemic. As Western Canadian Select ("WCS") prices improved from their April lows, the Company began reactivating certain low-cost heavy crude oil production in mid-May 2020, and has continued to ramp up production as oil prices improve. Approximately 185 bbl/d of higher cost heavy crude oil production remains shut-in at Mannville.

Realized revenue was $30.2 million in 2020, down $43.4 million (59%) from $73.6 million in 2019 due to the combined effect of the 44% decrease in annual production and lower realized revenue per boe. On a unit-of-production basis, realized revenue was $16.46/boe, 27% lower than the prior year period (2019 – $22.43/boe) and due primarily to lower realized natural gas and NGL prices of 69% and 23%, respectively. Compared to the AECO Daily Index price of $2.23/Mcf, realized natural gas prices were negatively impacted by physical and financial hedging losses of $12.0 million ($1.53/Mcf) which were primarily related to AECO-NYMEX basis differentials, and included a net loss of $0.5 million ($0.06/Mcf) related to modifications made to the natural gas market diversification contract. Market diversification contract revenue further reduced the realized natural gas price by $0.7 million or $0.09/Mcf in 2020, compared to an increase of $0.64/Mcf in 2019. For the year ended December 31, 2020, Perpetual's realized oil price was $49.37/bbl, up 10% from $44.87/bbl in 2019. Realized oil prices were improved by $19.05/bbl associated with realized hedging gains during the year (2019 – realized losses of $8.74/bbl).

Cash costs were $36.3 million in 2020, down $20.5 million (36%) from 2019. The decrease was due primarily to lower royalties, production and operating expenses and transportation costs associated with the 44% decrease in production, combined with lower general and administrative expense driven by a 25% reduction in Perpetual's corporate employee head count that was implemented late in the third quarter of 2019, along with the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. In 2020, the Company received total payments of $1.3 million from the CEWS and CERS programs which were recognized as a reduction to general and administrative and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). The deferral of Term Loan interest also reduced cash finance expense by $1.8 million during the year.

The net loss for 2020 was $61.6 million ($1.01/share), down from $94.0 million in 2019 ($1.56/share). The net loss in 2020 was impacted by aggregate non-cash impairment charges of $42.5 million (2019 – $47.1 million), comprised of $60.5 million of impairment charges booked at March 31, 2020, partially offset by an $18.0 million impairment reversal recorded at December 31, 2020. The net loss also included an unrealized loss of $0.9 million related to the change in fair value of the TOU share investment (2019 – $3.2 million) which was sold in the first quarter of 2020.

Net cash flows used in operating activities were $9.5 million in 2020, down $27.3 million compared to cash flows from operating activities of $17.8 million in 2019. The decrease was due primarily to the $43.4 million reduction in realized revenue, partially offset by a $20.5 million reduction in cash costs.

For the year ended December 31, 2020, adjusted funds flow was negative $7.8 million ($0.13/share), down $22.3 million from $14.5 million ($0.24/share) in 2019 as the impact of the 44% year-over-year decrease in production combined with lower natural gas and NGL prices outweighed the 36% decrease in cash costs.

FUTURE OPERATIONS

Perpetual has a first lien, reserve-based credit facility (the "Credit Facility"). On December 24, 2019, Perpetual's syndicate of lenders completed their semi-annual borrowing base redetermination, reducing the Credit Facility borrowing limit (the "Borrowing Limit") from $55 million to $45 million effective January 22, 2020.

In January 2020, the Company sold its remaining 1,000,000 TOU share investment for net cash proceeds of $14.3 million. Net proceeds were used to repay the outstanding TOU share margin demand loan of $0.1 million, with the balance applied to the Credit Facility. On April 1, 2020, the Company closed the East Edson Transaction. Net proceeds of $34.8 million were used to repay a portion of the Credit Facility. Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. As at December 31, 2020, $17.5 million was borrowed and $0.9 million of letters of credit were issued on the Credit Facility. The next Borrowing Limit redetermination is scheduled on or prior to March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. The semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's Term Loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021. The further extension of the Credit Facility repayment term is dependent on the Company's ability to repay or extend the term of the $45 million second lien Term Loan and deferred interest that matures and requires repayment on March 14, 2021. The Company remains dependent on the continued support of its lenders to extend approaching maturities.

During the year ended December 31, 2020, there was a dramatic decline in oil, natural gas, and NGL commodity prices due to local and global supply and demand imbalances and the COVID-19 pandemic. This contributed to a net working capital deficiency of $7.1 million as at December 31, 2020 and a $9.5 million use of cash from operations for the year then ended. The Company will require additional financing to fund the working capital deficiency and future operations, and to refinance the upcoming Credit Facility and Term Loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. In January 2021, the Company exchanged it's $33.6 million 8.75% unsecured senior notes due January 23, 2022 for new $33.6 million 8.75% third lien senior notes due January 23, 2025 (the "2025 Senior Notes"). Interest on the 2025 Senior Notes may be paid in-kind at the option of the Company by adding the interest payment to the principal amount owing. On January 23, 2021, the $1.5 million semi-annual interest payment on the 2025 Senior Notes was paid in-kind. Although cash flows from operations are forecast to improve for the next twelve-month period, Perpetual is considering other options including the extension of existing debt maturity dates, alternative financing, and the sale or monetization of additional assets.

Due to the facts and circumstances detailed above, coupled with considerable economic instability and uncertainty in the oil and gas industry which negatively impacts operating cash flows and lender and investor sentiment, there remains considerable risk around the Company's ability to address its liquidity shortfalls and upcoming maturities. In addition, there continues to be some uncertainty regarding the Statement of Claim which may restrict the Company's ability to manage its capital structure. As a result, there is material uncertainty surrounding the Company's ability to continue as a going concern that creates significant doubt as to the ability of the Company to meet its obligations as they come due. Therefore, the Company may be unable to realize its assets and discharge its liabilities in the normal course of business.

Perpetual's financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Corporation will be able to realize its assets and discharge its liabilities in the normal course of business. These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

SEQUOIA LITIGATION UPDATE

On January 13, 2020, the Court of Queen's Bench (the "Court") issued its written decision related to the Statement of Claim filed on August 3, 2018 against Perpetual and its President and Chief Executive Officer ("CEO") (the "Sequoia Litigation") with respect to the Company's disposition of shallow conventional natural gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Disposition"). The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed by PricewaterhouseCoopers Inc. ("PwC") LIT in its capacity as trustee in bankruptcy (the "Trustee") against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020.

On February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1st and 2nd, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings.

On January 14, 2021, the Court found that PwC could not establish a necessary element of the BIA claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded that there is "no merit" to the BIA claim and it summarily dismissed the balance of the Statement of Claim. PwC has subsequently appealed the decision (the "Second Appeal").

On January 25, 2021, the Court of Appeal issued their decision with respect to the First Appeal proceedings. The decision dismissed the appeal filed by Perpetual and granted certain aspects of the appeals filed by PwC, reinstating certain elements of the Sequoia Litigation for trial.

Management expects that the Company is more likely than not to be completely successful in defending against the Sequoia Litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's consolidated financial statements.

2021 OUTLOOK

Perpetual's reserve-based credit facility is currently undergoing its borrowing limit redetermination, which is scheduled to be completed on or prior to March 1, 2021 and its Term Loan matures on March 14, 2021. To preserve liquidity, the Company will defer further capital spending until the credit facility borrowing limit redetermination has been completed and the Term Loan has been refinanced or maturity extended. The Company will issue its 2021 Outlook once the borrowing limit redetermination is known and capital spending plans have been approved by the Board of Directors.

Production at Perpetual's non-operated West Central properties is expected to increase 25% to 30% from fourth quarter levels to 3,800 to 4,000 boe/d in the first quarter of 2021 (Q4 2020 – 3,033 boe/d). Production continues to ramp up at East Edson as new carried interest wells come onstream, with two (1.0 net) additional carried interest wells forecast to be on production by the end of March 2021. The Purchaser is anticipated to complete its eight well carried interest drilling commitment by the end of the third quarter of 2021.

Total abandonment and reclamation expenditures of up to $2.2 million are forecast in 2021, with up to $1.3 million to be funded through Alberta's Site Rehabilitation Program ("SRP").

2020 FOURTH QUARTER AND ANNUAL CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
Exploration and development	**464**	1,983	**5,975**	12,865
Corporate assets	**2**	12	**(36)**	74
Capital expenditures	**466**	1,995	**5,939**	12,939
Acquisitions	**–**	–	**222**	–
Proceeds from dispositions of oil and gas properties	**–**	–	**(34,750)**	–
Net capital expenditures	**466**	1,995	**(28,589)**	12,939

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
West Central	**441**	12	**476**	1,185
Eastern Alberta	**23**	1,971	**5,499**	11,680
Total	**464**	1,983	**5,975**	12,865

Wells drilled by area

	Three months ended December 31,		Years ended December 31,	
(gross/net)	**2020**	2019	**2020**	2019
West Central	**3/1.5**	–/–	**5/2.5**	–/–
Eastern Alberta	**–/–**	–/–	**4/4.0**	5/5.0(1)
Total	**3/1.5**	–/–	**9/6.5**	5/5.0(1)

(1) Excludes the re-entry of one existing well bore at Mannville.

Perpetual's exploration and development spending in the fourth quarter of 2020 was $0.5 million and was focused on maintenance projects at the East Edson property in West Central. Compared to the prior year period, expenditures decreased by 77% (Q4 2019 – $2.0 million). At the 50% owned East Edson property, three (1.5 net) horizontal Wilrich wells were drilled and tied-in to production during the fourth quarter pursuant to the Purchaser's carried interest drilling commitment, with the next two (1.0 net) wells forecast to be on production by the end of March 2021. Fourth quarter spending in Eastern Alberta was nominal, consistent with guidance released on November 10, 2020.

For the year ended December 31, 2020, exploration and development spending was $6.0 million, down 54% from 2019. This spending excludes the five (2.5 net) carried interest wells drilled at East Edson. The carried interest drilling program has confirmed a $102.9 million (63%) reduction in future development capital on the remaining 50% working interest at East Edson, reflecting the revised development plan which includes increased well spacing, longer extended-reach wells, and reduced capital costs per well related to the Purchaser's scale of operations as demonstrated by the execution of the 2020 drilling program. Spending in Eastern Alberta was $5.5 million, where four (4.0 net) multi-lateral heavy crude oil wells were drilled, completed and tied-in at Ukalta targeting the Clearwater formation, resulting in area F&D costs of $9.26/boe, including changes in FDC.

Acquisitions and Dispositions

On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta. The consideration received, and calculation of the gain (loss) recorded on disposition is summarized below:

($ thousands)	
Cash proceeds from disposition (a)	**34,750**
Drilling program rights received (b)	**18,000**
Retained East Edson royalty obligation (c)	**(6,996)**
Carrying amount of assets disposed (d)	**(52,803)**
Carrying amount of decommissioning obligations disposed (e)	**7,049**
Gain (loss) on disposition	**–**

a)	Cash proceeds from disposition	$35.0 million of cash received on closing, net of $0.2 million of transaction costs and closing adjustments. In order to reflect the nature of the proceeds received, cash proceeds from disposition have been allocated on the consolidated statements of cash flows to financing and investing activities in the amount of $7.0 million and $27.8 million, respectively.
b)	Drilling program rights received	$18.0 million of drilling program rights, comprised of the carried interest funding of the drill, complete, and tie-in costs for an eight-well drilling program. Five (2.5 net) horizontal wells targeting development of the Wilrich formation were drilled, completed and commenced production during the second half of 2020. The Purchaser is required to fulfill its entire commitment by April 1, 2022 and will be obligated to pay Perpetual $2.25 million for each commitment well not completed and having commenced production by this time.
c)	Retained East Edson royalty obligation	$7.0 million that Perpetual will retain until December 31, 2022 on behalf of the Purchaser, comprising the fair value of the Purchaser's 50% working interest in the existing gross overriding royalty on the East Edson property equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production. This obligation has been recorded in the consolidated statement of financial position under the heading "Royalty obligations".
d)	Carrying amount of assets disposed	$52.8 million of oil and gas properties ($50.4 million) and exploration and evaluation assets ($2.4 million).
e)	Carrying amount of decommissioning obligations disposed	$7.0 million of decommissioning obligations associated with oil and gas properties disposed.

Expenditures on decommissioning obligations

During the fourth quarter of 2020, Perpetual executed $0.9 million (Q4 2019 – $0.5 million) of abandonment and reclamation projects, of which $0.8 million was funded by Alberta's Site Rehabilitation Program ("SRP"). SRP funding is presented on the consolidated statements of loss and comprehensive loss as "other income". As part of Perpetual's focus on well and pipeline abandonment and reclamation, two reclamation certificates were received from the Alberta Energy Regulator ("AER") during the fourth quarter of 2020 (Q4 2019 – four reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. For the year ended December 31, 2020, Perpetual executed $1.0 million (2019 – $1.7 million) of abandonment and reclamation projects and received 13 reclamation certificates. Subsequent to year end, the Company has received six additional reclamation certificates related to projects completed in 2020. Total abandonment and reclamation expenditures of up to $2.2 million are forecast in 2021, with up to $1.3 million to be funded through the SRP.

SUMMARY OF QUARTERLY AND ANNUAL NET INCOME (LOSS)

Three months ended December 31,		**2020**		2019
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**9,456**	**21.73**	14,335	19.50
Royalties	**(1,831)**	**(4.21)**	(3,383)	(4.60)
Production and operating expenses	**(3,014)**	**(6.93)**	(3,839)	(5.22)
Transportation costs	**(804)**	**(1.85)**	(1,551)	(2.11)
Operating netback[(1)]	**3,807**	**8.74**	5,562	7.57
Unrealized change in fair value of derivatives	**(825)**	**(1.90)**	(3,369)	(4.58)
Gas over bitumen royalty credit	**211**	**0.48**	202	0.27
Other income	**812**	**1.87**	–	–
Exploration and evaluation	**(483)**	**(1.11)**	(811)	(1.10)
General and administrative	**(1,994)**	**(4.58)**	(2,406)	(3.27)
Share-based payments	**(517)**	**(1.19)**	(488)	(0.66)
Depletion and depreciation	**(2,906)**	**(6.68)**	(6,960)	(9.47)
Impairment reversal (impairment)	**18,000**	**41.36**	(24,452)	(33.26)
Finance expense	**(1,662)**	**(3.82)**	(2,981)	(4.05)
Change in fair value of TOU share investment	**–**	**–**	3,205	4.36
Net income (loss)	**14,443**	**33.17**	(32,498)	(44.19)
Net income (loss) per share - basic	**0.24**		(0.54)	

Years ended December 31,		**2020**		2019
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**30,194**	**16.46**	73,572	22.43
Royalties	**(6,571)**	**(3.58)**	(11,260)	(3.43)
Production and operating expenses	**(11,634)**	**(6.34)**	(18,332)	(5.59)
Transportation costs	**(3,617)**	**(1.97)**	(6,258)	(1.91)
Operating netback[(1)]	**8,372**	**4.57**	37,722	11.50
Unrealized change in fair value of derivatives	**9,901**	**5.40**	(21,893)	(6.67)
Gas over bitumen royalty credit	**685**	**0.37**	852	0.26
Other income	**812**	**0.44**	–	–
Exploration and evaluation	**(712)**	**(0.39)**	(1,797)	(0.55)
General and administrative	**(7,870)**	**(4.29)**	(11,660)	(3.55)
Share-based payments	**(2,017)**	**(1.10)**	(2,295)	(0.70)
Depletion and depreciation	**(15,533)**	**(8.47)**	(31,188)	(9.51)
Impairment, net of reversals	**(42,500)**	**(23.17)**	(47,052)	(14.34)
Finance expense	**(11,831)**	**(6.45)**	(11,951)	(3.64)
Change in fair value of TOU share investment	**(904)**	**(0.49)**	(3,207)	(0.98)
Restructuring costs	**–**	**–**	(1,546)	(0.47)
Net loss	**(61,597)**	**(33.58)**	(94,015)	(28.65)
Net loss per share - basic	**(1.01)**		(1.56)	

(1) See "Non-GAAP measures" in this MD&A.

Operating Netbacks

The following table highlights Perpetual's operating netbacks for the three months and years ended December 31, 2020 and 2019:

	Three months ended December 31, 2020			Three months ended December 31, 2019		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas ("P&NG") revenue[(1)]	**3,878**	**4,300**	**8,178**	9,366	6,464	15,830
Realized gains (losses) on derivatives[(2)(3)]	**–**	**–**	**1,278**	–	–	(1,495)
Royalties	**(1,241)**	**(590)**	**(1,831)**	(2,584)	(799)	(3,383)
Production and operating expenses	**(1,044)**	**(1,970)**	**(3,014)**	(1,698)	(2,141)	(3,839)
Transportation costs	**(339)**	**(465)**	**(804)**	(944)	(607)	(1,551)
Operating netback	**1,254**	**1,275**	**3,807**	4,140	2,917	5,562

	Year ended December 31, 2020			Year ended December 31, 2019		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas revenue[(1)]	**15,918**	**13,568**	**29,486**	47,199	27,162	74,361
Realized gains (losses) on derivatives[(2)(3)]	**–**	**–**	**708**	–	–	(789)
Royalties	**(5,030)**	**(1,541)**	**(6,571)**	(7,833)	(3,427)	(11,260)
Production and operating expenses	**(4,408)**	**(7,226)**	**(11,634)**	(7,188)	(11,144)	(18,332)
Transportation costs	**(2,055)**	**(1,562)**	**(3,617)**	(4,176)	(2,082)	(6,258)
Operating netback	**4,425**	**3,239**	**8,372**	28,002	10,509	37,722

($/boe)	Three months ended December 31, 2020 **West Central**	**Eastern**	**Total**	Three months ended December 31, 2019 West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**3,033**	**1,697**	**4,730**	6,253	1,738	7,991
Petroleum and natural gas revenue(1)	**13.90**	**27.55**	**18.79**	16.28	40.43	21.53
Realized gains (losses) on derivatives(2)(3)	**–**	**–**	**2.94**	–	–	(2.03)
Royalties	**(4.45)**	**(3.78)**	**(4.21)**	(4.49)	(5.00)	(4.60)
Production and operating expenses	**(3.74)**	**(12.62)**	**(6.93)**	(2.95)	(13.39)	(5.22)
Transportation costs	**(1.21)**	**(2.98)**	**(1.85)**	(1.64)	(3.80)	(2.11)
Operating netback	**4.50**	**8.17**	**8.74**	7.20	18.24	7.57

($/boe)	Year ended December 31, 2020 **West Central**	**Eastern**	**Total**	Year ended December 31, 2019 West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**3,525**	**1,487**	**5,012**	7,176	1,812	8,988
Petroleum and natural gas revenue(1)	**12.34**	**24.92**	**16.07**	18.02	41.06	22.67
Realized gains (losses) on derivatives(2)(3)	**–**	**–**	**0.39**	–	–	(0.24)
Royalties	**(3.90)**	**(2.83)**	**(3.58)**	(2.99)	(5.18)	(3.43)
Production and operating expenses	**(3.42)**	**(13.27)**	**(6.34)**	(2.74)	(16.84)	(5.59)
Transportation costs	**(1.59)**	**(2.87)**	**(1.97)**	(1.59)	(3.15)	(1.91)
Operating netback	**3.43**	**5.95**	**4.57**	10.70	15.89	11.50

(1) Includes revenues related to the natural gas market diversification contract and physical forward sales contracts which settled during the period.

(2) Includes realized gains and losses on financial derivatives and financial prompt month price optimization contracts. Realized gains and losses on financial derivatives are not allocated to the Company's core areas.

(3) For the fourth quarter of 2020, realized gains on derivatives include $0.5 million ($1.15/boe) of gains from the modification of the market diversification contract for the November 1, 2021 to October 31, 2022 period. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.26/boe) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period.

For the fourth quarter of 2020, Perpetual's operating netback was $3.8 million ($8.74/boe), down 32% from $5.6 million ($7.57/boe) in the comparative period of 2019. This decrease was driven primarily by the 41% drop in production compared to the prior year period, partially offset by lower costs. The significant decrease in production was the result of the East Edson Transaction which closed on April 1, 2020, combined with natural declines resulting from limited capital investment. For the fourth quarter of 2020, the Company's operating netback included $1.3 million in realized gains on financial derivatives (Q4 2019 – realized losses of $1.5 million), comprised of $2.2 million of gains from oil contracts, partially offset by losses of $0.9 million on financial natural gas contracts. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under its natural gas market diversification contract by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized gain on derivatives of $0.5 million ($1.15/boe) and increased the Company's realized natural gas price by $0.28/Mcf in the fourth quarter of 2020.

For the year ended December 31, 2020, Perpetual's operating netback was $8.4 million ($4.57/boe), down 78% from $37.7 million ($11.50/boe) in 2019. The decrease was due to a 44% decline in year-over-year production, combined with the 60% decrease in operating netback per boe, which was the result of lower realized natural gas and NGL prices of 69% and 23% respectively, combined with higher costs per boe. For the year ended December 31, 2020, the Company's operating netback included $0.7 million in net realized gains on financial derivatives (2019 – realized losses of $0.8 million), comprised of $7.5 million of gains from oil contracts, partially offset by losses of $6.8 million from financial natural gas and NGL contracts.

Production

	Three months ended December 31, **2020**	2019	Years ended December 31, **2020**	2019
Conventional natural gas (*MMcf/d*)				
Eastern Alberta	**2.7**	2.8	**2.5**	3.6
West Central	**16.8**	33.8	**19.0**	38.7
Total conventional natural gas(1)	**19.5**	36.6	**21.5**	42.3
Heavy crude oil (*bbl/d*)				
Eastern Alberta(2)	**1,240**	1,264	**1,076**	1,216
West Central	**1**	11	**6**	8
Total heavy crude oil	**1,241**	1,275	**1,082**	1,224
Total NGL (*bbl/d*)(3)	**237**	606	**346**	719
Total production (*boe/d*)	**4,730**	7,991	**5,012**	8,988

(1) Conventional natural gas production yielded a heat content of 1.16 GJ/Mcf for the fourth quarter of 2020 and 1.17 GJ/Mcf for the year ended December 31, 2020, resulting in higher realized natural gas prices on a $/Mcf basis. See "Commodity Prices".

(2) Primarily heavy crude oil.

(3) Primarily related to West Central liquids-rich conventional natural gas.

Fourth quarter production averaged 4,730 boe/d, down 3,261 boe/d or 41% from 7,991 boe/d in the prior year period, due primarily to the sale of a 50% working interest in the East Edson property in West Central Alberta. The closing of the East Edson Transaction reduced West Central production during the fourth quarter of 2020 by 3,220 boe/d when compared to the prior year period. Production was lower than the 5,100 to 5,300 boe/d guidance released on November 10, 2020 with the Company's third quarter results, as the three (1.5 net) carried interest East Edson wells were tied-in to production later than forecast and operational shut-ins related to frac operations were greater than anticipated. In the fourth quarter of 2020, the production mix increased to 31% heavy crude oil and NGL (Q4 2019 – 24% heavy crude oil and NGL), primarily as a result of the East Edson Transaction.

Fourth quarter conventional natural gas production averaged 19.5 MMcf/d, down 47% from 36.6 MMcf/d in the comparative period of 2019. Conventional natural gas production was impacted by the sale of the 50% working interest in the East Edson property. Compared to the third quarter of 2020, conventional natural gas production increased by 20% or 3.2 MMcf/d, due to the full quarter of production from two (1.0 net) carried interest East Edson wells that were tied-in late in the third quarter, and three (1.5 net) carried interest wells tied-in later in the fourth quarter. Fourth quarter production was impacted by approximately 115 boe/d associated with adjacent wells that were shut-in during completion operations on the three new wells. Two (1.0 net) additional East Edson carried interest wells are forecast to be on production by the end of March 2021.

Fourth quarter NGL production was 237 bbl/d, 61% lower than the comparative period of 2019, tracking lower conventional natural gas production from West Central and lower NGL yields from the five (2.5 net) new carried interest wells that have been tied-in to production during the second half of 2020. NGL yields at West Central were 14.1 bbls per MMcf in the fourth quarter of 2020, 21% lower than the comparative period of 2019 (Q4 2019 – 17.9 bbls per MMcf). Perpetual's average NGL sales composition for the fourth quarter of 2020 consisted of 61% condensate, comparable to the prior year period.

Heavy crude oil production in Eastern Alberta was 2% lower than the fourth quarter of 2019. Ukalta production averaged 472 bbl/d in the fourth quarter of 2020 (Q4 2019 – 150 bbl/d), reflecting production added from the four (4.0 net) new wells drilled in the first quarter of 2020. Drilling at Ukalta more than offset natural heavy crude oil declines, but approximately 185 bbl/d of higher cost heavy crude oil production at Mannville remained shut-in in response to the significant decline in global oil prices. The Company continues to ramp up production as oil prices recover.

For the year ended December 31, 2020, production decreased 44% to 5,012 boe/d compared to 8,988 boe/d in the prior year period. Production levels decreased through 2019 and the first half of 2020 with restricted capital spending in response to low and volatile Alberta natural gas prices, price-driven heavy crude oil shut-ins in the second quarter of 2020, and the April 1, 2020 50% working interest disposition of the East Edson property.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2020	2019	**2020**	2019
Reference prices				
NYMEX Daily Index (US*$/MMBtu*)	**2.66**	2.50	**2.08**	2.63
AECO Daily Index (*$/GJ*)	**2.50**	2.35	**2.11**	1.67
AECO Daily Index (*$/Mcf*)(1)	**2.64**	2.48	**2.23**	1.76
Alberta Gas Reference Price (*$/GJ*)(2)	**2.32**	2.01	**1.90**	1.40
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**42.66**	56.96	**39.40**	57.03
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(9.30)**	(15.83)	**(12.60)**	(12.76)
WCS average (*Cdn$/bbl*)(3)	**43.37**	54.29	**35.91**	58.88
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**2.64**	2.48	**2.23**	1.76
Heat Content Premium(4)	**0.27**	0.27	**0.24**	0.19
Market Diversification Contract	**(0.37)**	(0.05)	**(0.09)**	0.64
Realized gains (losses) on financial and physical gas derivatives(6)	**(1.18)**	(0.56)	**(1.53)**	0.16
Realized gains (losses) on prompt month price optimization	**0.10**	(0.14)	**–**	0.02
Realized natural gas price (*$/Mcf*)(5)	**1.46**	2.00	**0.85**	2.77
Percent of AECO Daily Index	**55%**	81%	**38%**	157%
Realized oil price (*$/bbl*)(5)	**52.60**	43.85	**49.37**	44.87
Realized natural gas liquids ("NGL") price (*$/bbl*)(5)	**38.03**	43.93	**31.40**	41.01

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) The Alberta Gas Reference Price is a representative market price for natural gas bought and sold within the province and is used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.30 for the three months ended December 31, 2020 (Q4 2019 – $1.32) and $1.34 for the year ended December 31, 2020 (2019 – $1.33).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.16 GJ/Mcf for the fourth quarter of 2020 and 1.17 GJ/Mcf for the year ended December 31, 2020. Perpetual received a 10% premium to the AECO Daily Index for the fourth quarter of 2020 (Q4 2019 – 11%) and an 11% premium for the year ended December 31, 2020 (2019 – 11%) related to its higher average heat content.
(5) Realized natural gas, oil and NGL prices include physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives and foreign exchange contracts.
(6) For the fourth quarter of 2020, realized gains on derivatives include $0.5 million ($0.28/Mcf) of gains from the modification of the natural gas market diversification contract for the November 1, 2021 to October 31, 2022 period. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.06/Mcf) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period. For the year ended December 31, 2019, realized gains on derivatives include $2.7 million ($0.17/Mcf) from the elimination of the Company's 40,000 MMBtu/d market diversification contract obligations for the period of December 1, 2019 to October 31, 2020.

The fourth quarter of 2020 began with United States ("US") natural gas inventories approximately 310 Bcf above the 5-year average level. With global inventories of natural gas above historical averages, global LNG prices dropped to levels that resulted in low utilization of US LNG export capacity. The threat of early winter cold in North America, combined with flat production levels and higher LNG utilization, led to a price rally early in the fourth quarter of 2020. As the fourth quarter continued and cold weather failed to materialize, the elevated storage inventories weighed on the market, causing NYMEX natural gas prices to decline. For the fourth quarter of 2020, NYMEX natural gas prices increased 6% to US$2.66/MMBtu (Q4 2019 - US$2.50/MMBtu), while AECO Daily Index prices also increased 6% over the same period to $2.50/GJ (Q4 2019 – $2.35/GJ). The increase in AECO pricing was due to lower in-basin production compared to the prior year period, combined with increased exports to the Eastern and Western US markets. This led to strong storage withdrawals in Alberta and AECO-NYMEX basis to average US$0.56/MMBtu for the fourth quarter of 2020 (Q4 2019 – US$0.73/MMBtu). The North American drilling rig count remains wells below prior year levels.

WTI averaged US$42.66/bbl in the fourth quarter of 2020 (Q4 2019 – US$56.96/bbl). The decrease from the comparative period was related to significantly lower global demand driven by the economic contraction caused by the COVID-19 pandemic. Compared to the third quarter of 2020, WTI prices saw increased volatility due to overall financial market volatility, uncertainties associated with the US Presidential election campaign, a resurgence of COVID-19 induced shutdowns, and dissent between OPEC+ member countries which led to increased uncertainty. A turning point was reached in November 2020 following the US election, coinciding with positive vaccine developments and lower tensions among OPEC+ member countries. These factors led WTI crude, and equity markets to rally significantly through the second half of the fourth quarter. Focus remains on the global supply-demand balance, with OPEC continuing to help provide balance and bring global inventories back to normal levels. Concurrently, the US drilling rig count recovered from its summer 2020 lows but remains well below prior year levels.

The WCS differential tightened from an average US$15.83/bbl in the fourth quarter of 2019 to US$9.30/bbl in the fourth quarter of 2020. Production curtailments, facility turnarounds and natural production declines impacted the supply-demand balance in Alberta resulting in historically strong WCS differentials. These factors, combined with strong Gulf Coast Heavy Sour Mix pricing, led to a higher demand for Canadian heavy barrels. During the quarter, the government of Alberta lifted its curtailment program leading to increased domestic production for December 2020. As local inventories remain below 2019 levels, the market has increased confidence that it can remain balanced as incremental pipeline takeaway capacity is scheduled to come online later in 2021.

Perpetual's realized natural gas price, including derivatives, decreased 27% to $1.46/Mcf in the fourth quarter of 2020 from $2.00/Mcf in the comparative period of 2019. Compared to the AECO Daily Index, lower realized natural gas prices were the result of AECO-NYMEX basis hedging losses of $2.6 million ($1.46/Mcf) on financial and physical contracts, which occurred as Western Canadian gas storage filled rapidly. During the second quarter of 2020, the Company locked-in these remaining AECO-NYMEX basis hedge positions by entering into substantially offsetting hedge arrangements for the remainder of 2020 and 2021. The Company expects to realize a further loss of $3.4 million in 2021 on these locked-in positions. In the fourth quarter of 2020, the Company recorded a realized gain of $0.5 million ($0.28/Mcf) from the modification of the market diversification contract for the November 1, 2021 to October 31, 2022 period. In addition, the market diversification contract reduced the Company's realized natural gas price by $0.7 million ($0.37/Mcf) during the fourth quarter due to the relative increase in AECO Daily Index prices compared to the ex-AECO market hubs. In February 2021, the Company's remaining 10,000 MMBtu/d market diversification contract obligations were eliminated for the period of April 1, 2021 to October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes.

For the year ended December 31, 2020, Perpetual's realized natural gas price was $0.85/Mcf, down 69% from $2.77/Mcf in 2019 for the same reasons noted above. The market diversification contract reduced the Company's realized natural gas price by $0.7 million ($0.09/Mcf) due to the relative increase in AECO Daily Index prices compared to the two remaining downstream markets. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.06/Mcf) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period.

In the third quarter of 2020, the Company reduced its fixed volume obligations under the market diversification contract by 30,000 MMBtu/d to 10,000 MMBtu/d for the period commencing November 1, 2020 and ending on October 31, 2021 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized loss on derivatives of $1.0 million. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under the market diversification contract by 14,600 MMBtu/d to 25,400 MMBtu/d for the period November 1, 2021 to October 31, 2022, resulting in a realized gain of $0.5 million. The net impact of these modifications was a realized loss of $0.5 million or $0.06/Mcf for the year ended December 31, 2020. In the third quarter of 2019, the Company's 40,000 MMBtu/d market diversification contract obligations were eliminated for the period of December 1, 2019 to October 31, 2020 in response to TC Energy's changes to maintenance operating protocols, in order to shift the pricing point back to AECO, resulting in a realized gain of $2.7 million ($0.17/Mcf). Market diversification contract pricing is based on daily index prices at pricing hubs outside of Alberta that generally track North American NYMEX prices. See "Natural Gas Sales Obligations" on page 18 of this MD&A for sales volume obligations by price hub. Approximately 25% of 2021 forecast conventional natural gas production and 80% of 2022 forecast conventional natural gas production is expected to be delivered to the market diversification contract, with remaining production exposed to AECO prices.

During the fourth quarter of 2020, the average heat content conversion ratio for Perpetual's conventional natural gas production was 1.16 GJ:1 Mcf, consistent with the comparative period of 2019. Conventional natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas.

Perpetual's realized oil price for the fourth quarter of 2020 was $52.60/bbl, 20% higher than the fourth quarter of 2019 due to realized gains on crude oil derivative contracts of $2.2 million ($18.92/bbl) that were entered into in late 2019, prior to the collapse of oil prices. Conversely, Perpetual's realized oil price in the fourth quarter of 2019 was reduced by $6.18/bbl associated with realized hedging losses.

For the year ended December 31, 2020, Perpetual's realized oil price was $49.37/bbl, up 10% from $44.87/bbl in 2019. Realized oil prices were improved by $19.05/bbl associated with realized hedging gains during the year (2019 – realized losses of $8.74/bbl).

Perpetual's realized NGL price for the fourth quarter of 2020 was $38.03/bbl, down 13% from the fourth quarter of 2019, reflecting a decrease in all NGL component prices which moved lower in concert with lower WTI light oil prices. For the year ended December 31, 2020, Perpetual's realized NGL price was $31.40/bbl, down 23% from the prior year period. The decrease was due to lower WTI light oil prices combined with realized hedging losses of $1.35/bbl on Perpetual's 350 bbl/d basis differential hedge between WTI and Edmonton condensate pricing that expired on June 30, 2020.

Revenue

($ thousands, except as noted)	Three months ended December 31, 2020	2019	Years ended December 31, 2020	2019
Petroleum and natural gas revenue				
Natural gas[1]	**3,502**	7,263	**13,329**	39,318
Oil[1]	**3,846**	5,867	**12,015**	23,958
NGL	**830**	2,700	**4,142**	11,085
Petroleum and natural gas revenue	**8,178**	15,830	**29,486**	74,361
Realized gains (losses) on derivatives[2]	**1,278**	(1,495)	**708**	(789)
Realized revenue	**9,456**	14,335	**30,194**	73,572
Unrealized gains (losses) on derivatives	**(825)**	(3,369)	**9,901**	(21,893)
Total revenue	**8,631**	10,966	**40,095**	51,679
Realized revenue *($/boe)*	**21.73**	19.50	**16.46**	22.43
Total revenue *($/boe)*	**19.83**	14.92	**21.86**	15.75

(1) Includes revenues related to the market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains and losses on financial derivatives and certain financial prompt month price optimization contracts.

Perpetual's petroleum and natural gas ("P&NG") revenue, before financial derivatives, for the three months ended December 31, 2020 of $8.2 million decreased 48% from the fourth quarter of 2019, due to the 41% decrease in average daily production combined with the impact of physical hedging losses on AECO-NYMEX basis natural gas contracts. For the year ended December 31, 2020, P&NG revenue decreased 60% compared to the prior year period, following the 44% decrease in average daily production combined with the decrease in crude oil and NGL reference prices along with physical AECO-NYMEX basis hedging losses.

Natural gas revenue, before derivatives, of $3.5 million in the fourth quarter of 2020 comprised 43% (Q4 2019 – 46%) of total P&NG revenue while conventional natural gas production was 69% (Q4 2019 – 76%) of total production. Natural gas revenue decreased 52% from $7.3 million in the fourth quarter of 2019, reflecting the combined impact of physical hedging losses, reduced revenue from the market diversification contract, and the 47% decrease in conventional natural gas production volumes driven by the East Edson Transaction.

Oil revenue of $3.8 million represented 47% (Q4 2019 – 37%) of total P&NG revenue while heavy crude oil production was 26% (Q4 2019 – 16%) of total production. Oil revenue was 34% lower than the same period in 2019, due primarily to the 20% decline in WCS average prices to $43.37/bbl (Q4 2019 – $54.29/bbl), as heavy crude oil production only declined by 3% over the same period. The lower WCS average reference price of $43.37/bbl was the result of a 25% decrease in WTI light oil prices to US$42.66/bbl (Q4 2019 – US$56.96/bbl) combined with a weaker US dollar of US$1.00 = Cdn$1.30 (Q4 2019 – $1.32), which more than offset a 41% narrowing of the WCS differential to US$9.30/bbl (Q4 2019 – US$15.83/bbl) compared to the prior year period. For the year ended December 31, 2020, oil revenue declined by 50% due to the 12% decrease in heavy crude oil production in combination with a 39% decrease in WCS average prices.

NGL revenue for the fourth quarter of 2020 of $0.8 million comprised 10% (Q4 2019 – 17%) of total P&NG revenue while NGL production represented only 5% (Q4 2019 – 8%) of total Company production. NGL revenue decreased by 69% over the comparative period of 2019 (Q4 2019 – $2.7 million) while NGL production decreased 61%, reflecting the decrease in all NGL component prices compared to the prior year period which generally track WTI light oil prices. For the year ended December 31, 2020, NGL revenue decreased by 63% due to the 52% decrease in NGL production combined with a 23% decrease in realized NGL prices over the prior year. The decrease in NGL production reflected lower conventional natural gas production at East Edson, combined with slightly lower NGL yields of 18.2 bbls per MMcf of conventional natural gas production (2019 – 18.6 bbls per MMcf).

Unrealized losses on derivatives of $0.8 million were recorded in the fourth quarter of 2020 (Q4 2019 – unrealized loss of $3.4 million). For the year ended December 31, 2020, Perpetual recorded net unrealized gains of $9.9 million, due primarily to the increased value of the Company's fixed price WTI and WCS oil contracts as global oil prices declined. Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of cash flow from (used in) operating activities as they are non-cash. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands, except as noted)	Three months ended December 31, 2020	2019	Years ended December 31, 2020	2019
Crown	**451**	838	**1,382**	2,313
Freehold and overriding[1]	**1,380**	2,545	**5,189**	8,947
Total	**1,831**	3,383	**6,571**	11,260
Crown (*% of P&NG revenue*)	**5.5**	5.3	**4.7**	3.1
Freehold and overriding (*% of P&NG revenue*)	**16.9**	16.1	**17.6**	12.0
Total (*% of P&NG revenue*)	**22.4**	21.4	**22.3**	15.1
$/boe	**4.21**	4.60	**3.58**	3.43

(1) Includes $0.9 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2020 (Q4 2019 – $1.9 million) and $3.9 million for the year ended December 31, 2020 (2019 – $5.7 million). Excludes the Purchaser's 50% working interest in the existing gross overriding royalty obligation, which is paid in-kind and settled through non-cash delivery of contractual natural gas and associated NGL volumes until December 31, 2022.

Royalty expense for the fourth quarter of 2020 was $1.8 million, representing 22.4% of P&NG revenue (Q4 2019 – 21.4%) and down 46% from $3.4 million in the prior year period. Higher royalty rates reflect the 15% increase in the Alberta Gas Reference Price and the 6% increase in the AECO Daily Index price compared to the prior year period which are used to calculate crown royalty and freehold and overriding royalty expense, respectively.

Freehold and overriding royalties have decreased 46% from the fourth quarter of 2019, due to the impact of the East Edson Transaction, partially offset by higher AECO Daily Index prices. The East Edson gross overriding royalty is equivalent to a maximum of 5.6 MMcf/d of conventional natural gas and associated NGL production. As part of the East Edson Transaction, Perpetual agreed to retain the Purchaser's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production for the period of April 1, 2020 to December 31, 2022. This additional obligation has been recorded in the consolidated statements of financial position under the heading "Royalty obligations". The retained East Edson royalty obligation is paid in-kind and settled through non-cash delivery of contractual natural gas and associated NGL volumes to the royalty holder.

For the year ended December 31, 2020, royalty expense was $6.6 million, representing 22.3% of P&NG revenue (2019 – 15.1%) and down 42% from $11.3 million in the prior year period. Average crown royalty rates increased to 4.7% in 2020 compared to 3.1% in 2019, due primarily to the 36% increase in Alberta Gas Reference Prices compared to the prior year, as well as the higher percentage of heavy crude oil in the production mix. Freehold and overriding royalties also increased as a percentage of P&NG revenue from 12.0% to 17.6%, as the AECO Daily Index increased 26% to $2.11/GJ (2019 – $1.67/GJ). In addition, as East Edson production decreased for much of 2020, the fixed volume nature of the gross overriding royalty resulted in an increased expense as a percentage of revenue and on a unit-of-production basis, which also contributed to the increased overriding royalty rate in 2020.

Production and operating expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Production and operating expenses	**3,014**	3,839	**11,634**	18,332
$/boe	**6.93**	5.22	**6.34**	5.59

On an absolute dollar basis, production and operating costs were down by $0.8 million (21%) over the prior year period. This decrease reflects the impact of the East Edson Transaction, the elimination of variable costs related to the ongoing shut-in of 185 bbl/d of higher cost heavy crude oil production at Mannville, and other cost mitigation initiatives. Production and operating expenses were up 33% on a unit-of-production basis to $6.93/boe for the fourth quarter of 2020, compared to $5.22/boe for the comparable period of 2019 which reflects the increase in the Eastern Alberta production mix following the East Edson Transaction, which has higher operating costs compared to West Central.

For the year ended December 31, 2020, West Central production and operating costs increased by 25% on a unit-of-production basis to $3.42/boe (2019 – $2.74/boe). This increase includes $0.3 million of costs associated with the five-day West Wolf Lake plant turnaround, combined with natural production declines prior to the commencement of the carried interest drilling program at East Edson. Eastern Alberta operating costs decreased 21% to $13.27/boe over the same period (2019 – $16.85/boe) as a result of cost optimization activities and the continued temporary shut-in of certain higher cost heavy crude oil wells at Mannville.

Transportation costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Transportation costs	**804**	1,551	**3,617**	6,258
$/boe	**1.85**	2.11	**1.97**	1.91

Transportation costs include clean oil trucking and NGL transportation, as well as costs to transport natural gas from the plant gate to commercial sales points. For the fourth quarter of 2020, transportation costs were $0.8 million, down 48% from the prior year period of $1.6 million. On a unit-of-production basis, company-wide transportation costs decreased by 12% to $1.85/boe in the fourth quarter of 2020 (Q4 2019 – $2.11/boe), due to a reduction in Perpetual's natural gas firm transportation capacity from 25.5 MMcf/d to 15.4 MMcf/d, eliminating unutilized demand charges at East Edson. Fourth quarter transportation costs averaged $1.21/boe at West Central compared to $2.98/boe for production from Eastern Alberta.

For the year ended December 31, 2020, transportation costs were $3.6 million, a decrease of 42% over the prior year period. The decrease was driven by a 44% decrease in total production, as per unit transportation costs of $1.97/boe were only 3% higher than the prior year period (2019 – $1.91/boe).

Exploration and evaluation ("E&E") expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
Lease rentals	**19**	52	**164**	190
Geological and geophysical costs	**–**	–	**19**	8
Lease expiries (non-cash)	**464**	759	**529**	1,599
Total E&E expense	**483**	811	**712**	1,797

Exploration and evaluation expenses include lease rentals on undeveloped acreage, geological and geophysical costs, and the write-down of carrying costs related to lease expiries. During the year ended December 31, 2020, the Company recorded $0.5 million of non-cash write-downs (2019 – $1.6 million) associated with certain P&NG leases deemed to no longer be part of Perpetual's future development plans.

General and administrative ("G&A") expenses

($ thousands, except as noted)	Three months ended December 31, **2020**	2019	Years ended December 31, **2020**	2019
Cash G&A expense	**2,011**	2,604	**8,300**	12,808
Overhead recoveries	**(17)**	(198)	**(430)**	(1,148)
Total G&A expense	**1,994**	2,406	**7,870**	11,660
$/boe	**4.58**	3.27	**4.29**	3.55

During the fourth quarter of 2020, cash G&A expense was $2.0 million, a 23% decrease from the prior year period of $2.6 million due primarily to the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. During the fourth quarter of 2020, the Company received payments through the Canada Emergency Wage Subsidy of $0.3 million. These grants were recognized as a reduction to general and administrative and production and operating expenses of $0.2 million and $0.1 million, respectively (Q4 2019 – nil). Overhead recoveries decreased by 91% over the same period, due to reduced cash G&A expense associated with the transfer of operatorship at East Edson and decreased capital expenditures associated with the Company's decision to defer capital spending until oil prices recover and stabilize. On a unit-of-production basis, total G&A expense was up 40% to $4.58/boe for the fourth quarter of 2020 (Q4 2019 - $3.27/boe), as lower costs were more than offset by the 41% decline in production compared to the prior year period.

For the year ended December 31, 2020, total G&A expense was $7.9 million, down 33% from the prior year (2019 – $11.7 million). The decrease was driven by the 25% reduction in Perpetual's corporate employee head count that was implemented late in the third quarter of 2019, combined with the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. For the year ended December 31, 2020, the Company received payments through the Canada Emergency Wage Subsidy of $1.3 million. These grants were recognized as a reduction to G&A and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). These reductions were partially offset by Sequoia Litigation legal costs and lower overhead recoveries triggered by the reduction in exploration and development spending from $12.9 million in 2019 to $6.0 million in 2020. On a unit-of-production basis, total G&A expense increased by 21% to $4.29/boe for the year ended December 31, 2020 (2019 – $3.55/boe), as lower costs were more than offset by the 44% decline in production compared to the prior year.

Share-based payments

($ thousands, except as noted)	Three months ended December 31, **2020**	2019	Years ended December 31, **2020**	2019
Share-based payments (non-cash)	**104**	123	**517**	406
Share-based payments (cash)	**413**	365	**1,500**	1,889
Total share-based payments	**517**	488	**2,017**	2,295

Share-based payments expense for the fourth quarter of 2020 was $0.5 million, unchanged from the comparative period of 2019. During the fourth quarter of 2020, 0.2 million deferred shares were granted to Directors of the Company, with no further grants to employees. For the year ended December 31, 2020, share-based payments expense was $2.0 million, 12% lower than the prior year due to a reduction in the value of outstanding awards.

Depletion and depreciation

($ thousands, except as noted)	Three months ended December 31, **2020**	2019	Years ended December 31, **2020**	2019
Depletion and depreciation	**2,906**	6,960	**15,533**	31,188
$/boe	**6.68**	9.47	**8.47**	9.51

Perpetual recorded $2.9 million of depletion and depreciation expense for the fourth quarter of 2020, down 58% from the prior year period (Q4 2019 – $7.0 million). The decrease reflects the 41% decline in production volumes compared to the prior year period, combined with lower depletion rates on a unit-of-production.

Perpetual recorded $15.5 million of depletion and depreciation expense for the year ended December 31, 2020, down 50% from $31.2 million in 2019, due primarily to the 44% decline in production volumes compared to the prior year period. On a unit-of-production basis, depletion and depreciation expense decreased by 11% to $8.47/boe (2019 – $9.51/boe) due to non-cash impairments recognized in the fourth quarter of 2019 and the first quarter of 2020 (Q4 2019 – $24.5 million; Q1 2020 – $50.3 million).

Impairment

In accordance with IFRS, the Company is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. At December 31, 2020, the Company conducted an assessment of indicators of impairment and impairment reversal for all the Company's cash-generating units ("CGUs"). In performing the assessment, management determined that the recovery in global oil and gas commodity prices, changing development plans, positive reserve revisions, and increasing economic stability and certainty in the oil and gas industry, all of which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. The estimated recoverable amounts of the CGUs were determined on a value-in-use basis using estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserves evaluators at December 31, 2020, along with oil and gas commodity price estimates based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 12% and 25% to consider risks specific to the CGUs.

At December 31, 2020, the Company determined that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded the carrying amounts of $81.2 million and $24.7 million, respectively. Accordingly, an aggregate non-cash impairment reversal of $18.0 million was included in net income (loss).

At March 31, 2020, the Company conducted an assessment of internal and external indicators of impairment for all the Company's CGUs. In performing the assessment, management determined that the significant decline in global oil and gas commodity prices that was experienced following the onset of the COVID-19 pandemic, coupled with the considerable economic instability and uncertainty in the oil and gas industry which negatively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. At March 31, 2020, the Company determined that the carrying amounts of the West Central CGU and Eastern Alberta CGU exceeded the estimated recoverable amounts and accordingly, an aggregate non-cash impairment charge of $50.3 million was included in net loss. For the year ended December 31, 2020, the Company has recorded an aggregate non-cash impairment charge of $32.3 million related to these CGUs in net loss.

E&E assets are tested for impairment both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and natural gas properties in property, plant and equipment. At December 31, 2020, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets. In performing the assessment, management determined that the recovery in global oil and gas commodity prices from depressed levels experienced earlier in 2020, coupled with the increasing economic stability and certainty in the oil and gas industry which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of E&E assets. The estimated recoverable amount was determined based on the sales value of undeveloped lands. As a result of this calculation, no impairment or impairment reversal was recognized during the fourth quarter of 2020.

At March 31, 2020, management determined that the significant decline in global oil and gas prices, coupled with the considerable economic instability and uncertainty in the oil and gas industry, justified calculation of the estimated recoverable amount of E&E assets. As a result of this calculation, the carrying value of E&E assets was written down to the estimated recoverable amount, resulting in a non-cash impairment charge of $10.2 million.

Finance expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2020**	2019	**2020**	2019
Cash finance expense				
Interest on revolving bank debt	**293**	788	**1,662**	2,880
Interest on TOU share margin demand loan	**–**	72	**–**	407
Interest on term loan	**(912)**	936	**1,812**	3,645
Interest on senior notes	**733**	735	**2,938**	2,921
Interest on lease liabilities	**41**	44	**175**	189
Dividend income from TOU share investment	**–**	(199)	**–**	(762)
Total cash finance expense	**155**	2,376	**6,587**	9,280
Non-cash finance expense				
Interest paid in-kind	**1,823**	–	**1,823**	–
Amortization of debt issue costs	**502**	326	**1,673**	1,187
Accretion on decommissioning obligations	**96**	162	**443**	752
Change in fair value of royalty obligations	**(914)**	117	**1,305**	732
Total non-cash finance expense	**1,507**	605	**5,244**	2,671
Finance expenses recognized in net loss	**1,662**	2,981	**11,831**	11,951

Total cash finance expense was $0.2 million in the fourth quarter of 2020, 93% lower than the prior year period (Q4 2019 – $2.4 million). The decrease was due primarily to $1.8 million of Term Loan interest for the July 1, 2020 to December 31, 2020 period that the lender agreed could be paid in-kind and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021. Interest on revolving bank debt also decreased by $0.5 million due to lower average borrowings and lower floating interest rates.

In January 2020, the Company sold its remaining 1,000,000 TOU share investment and used the net cash proceeds of $14.3 million to repay the remaining $0.1 million TOU share margin demand loan, with the balance used to repay a portion of the Credit Facility. Accordingly, the Company no longer receives dividend income from its TOU share investment or incurs interest expense on the TOU share margin demand loan.

Total non-cash finance expense for the fourth quarter of 2020 was $1.5 million, $0.9 million higher than the prior year period (Q4 2019 – $0.6 million) and due primarily to $1.8 million of Term Loan interest for the July 1, 2020 to December 31, 2020 period that the lender agreed could be paid in-kind. For the year ended December 31, 2020, total non-cash finance expense was $5.2 million, an increase of 96% from the prior year (2019 – $2.7 million). The increase included $1.8 million of interest paid in-kind on the Term Loan (2019 – nil) and the change in fair value of royalty obligations of $1.3 million (2019 – $0.7 million) which resulted from higher AECO future natural gas prices.

In January 2021, the Company exchanged it's $33.6 million 8.75% unsecured senior notes due January 23, 2022 for new $33.6 million 8.75% third lien senior notes due January 23, 2025. Interest on the 2025 Senior Notes may be paid in-kind at the option of the Company by adding the interest payment to the principal amount owing. On January 23, 2021, the $1.5 million semi-annual interest on the 2025 Senior Notes was paid in-kind, increasing the principal amount owing to $35.0 million. Perpetual intends to pay in-kind the 2025 Senior Notes semi-annual interest payment due on July 23, 2021.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual's strategy targets the maintenance of a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions such as depressed commodity prices, available liquidity, and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, the Term Loan, revolving bank debt, and net working capital. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short-term liquidity and long-term financial sustainability.

Capital Management

(*$ thousands, except as noted*)	**December 31, 2020**	December 31, 2019
Revolving bank debt	**17,495**	47,552
Term loan, principal amount	**46,823**	45,000
TOU share margin demand loan, principal amount	**–**	100
Senior notes, principal amount	**33,580**	33,580
TOU share investment(1)	**–**	(15,220)
Net working capital deficiency(2)	**7,099**	7,068
Net debt(2)	**104,997**	118,080
Shares outstanding at end of period (*thousands*)(3)	**61,305**	60,513
Market price at end of period (*$/share*)(3)	**0.08**	0.07
Market value of shares	**4,904**	4,236
Enterprise value(2)	**109,901**	122,316
Net debt as a percentage of enterprise value	**96**	97
Trailing twelve months adjusted funds flow(2)	**(7,787)**	14,534
Net debt to trailing twelve months adjusted funds flow	**N/A**	8.1

(1) The TOU share investment is valued based on the December 31, 2019 closing price per the Toronto Stock Exchange ($15.22 per share) and 1.0 million TOU shares held.
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2020, Perpetual had total net debt of $105.0 million, down $13.1 million (11%) from December 31, 2019 due to the closing of the East Edson Transaction on April 1, 2020 for consideration including net cash proceeds of $34.8 million. The cash proceeds from the East Edson Transaction were used to repay bank debt. Compared to September 30, 2020, net debt increased by $2.9 million (3%) due to increased draws on the Credit Facility to fund net working capital payments and cash flows used in operating activities.

Perpetual had available liquidity at December 31, 2020 of $1.6 million, comprised of the $20 million Credit Facility Borrowing Limit, less current borrowings and letters of credit of $17.5 million and $0.9 million, respectively.

Revolving bank debt

As at December 31, 2020, the Company's Credit Facility had a Borrowing Limit of $20.0 million (December 31, 2019 – $55.0 million) under which $17.5 million was drawn (December 31, 2019 – $47.6 million) and $0.9 million of letters of credit had been issued (December 31, 2019 – $2.3 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%. The effective interest rate on the Credit Facility at December 31, 2020 was 6.95%. For the period ended December 31, 2020, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.2 million.

Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. The next Borrowing Limit redetermination, and current maturity date, is scheduled to be completed by March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020. Previously, on December 24, 2019, Perpetual's syndicate of Credit Facility lenders completed their semi-annual borrowing base redetermination, reducing the Borrowing Limit from $55 million to $45 million on January 22, 2020.

The Credit Facility is secured by general, first lien security agreements covering all present and future property of the Company and its subsidiaries, with the exception of certain lands pledged to the gas over bitumen royalty financing counterparty. The Credit Facility also contains provisions which restrict the Company's ability to repay Term Loan and senior note principal and interest, and to pay dividends on or repurchase its common shares.

At December 31, 2020, the Credit Facility was not subject to any additional financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

			December 31, 2020		December 31, 2019	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term Loan	March 14, 2021	8.1%	**$ 46,823**	**$ 46,691**	$ 45,000	$ 44,274

The Term Loan bears a fixed interest rate of 8.1% with semi-annual interest payments due June 30th and December 31st of each year. In the fourth quarter of 2020, the Company and lender reached an agreement, allowing outstanding interest amounts of $1.8 million related to the December 31st payment to be paid-in-kind and added to the outstanding principal amount of the loan.

Amounts borrowed under the Term Loan that are repaid are not available for re-borrowing. The Company may repay the Term Loan at any time without penalty. The Term Loan matures and is repayable on March 14, 2021 and has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020.

The Term Loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and covenants as the Credit Facility. The Term Loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2020, the Term Loan is presented net of $0.1 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.2%.

At December 31, 2020, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			December 31, 2020		December 31, 2019	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2022 Senior Notes	January 23, 2022	8.75%	**$ 33,580**	**$ 32,359**	$ 33,580	$ 32,255

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23rd and July 23rd of each year. The senior notes are direct senior unsecured obligations of the Company, ranking pari passu with all other present and future unsecured and unsubordinated indebtedness of the Company. The Company may redeem the senior notes without any repayment penalty.

At December 31, 2020, the 2022 Senior Notes are recorded at the present value of future cash flows, net of 1.2 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 12.4%.

The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases. At December 31, 2020, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $14.6 million of the 2022 Senior Notes outstanding. An entity that is associated with the Company's CEO holds an additional $9.1 million of the 2022 Senior Notes outstanding.

On January 22, 2021, the Company announced the completion of a Court-approved plan of arrangement whereby the 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025 (the "2025 Senior Notes"). The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in either cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 interest payment of $1.5 million by a PIK Interest Payment which increased the principal amount of the 2025 Senior Notes outstanding to $35.0 million.

Equity

At December 31, 2020 there were 61.3 million common shares outstanding, net of 0.6 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2020 were 61.3 million (Q4 2019 – 60.4 million) and 61.0 million for the year ended December 31, 2020 (2019 – 60.3 million).

At February 24, 2021, there were 61.4 million common shares outstanding which is net of 0.6 million shares held in trust for employee compensation programs. In addition, the following potentially issuable common shares were outstanding as at the date of this MD&A:

(millions)	**February 24, 2021**
Share options	**5.4**
Performance share rights	**3.4**
Compensation awards	**7.5**
Total[1]	**16.3**

(1) 4.6 million compensation awards, 0.9 million share options, and 3.4 million performance share rights have an exercise price below the December 31, 2020 closing price of the Company's common shares of $0.08 per share.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2020**	Q3 2020	Q2 2020	Q1 2020
Financial				
Oil and natural gas revenue	**8,178**	7,089	3,722	10,497
Net income (loss)	**14,443**	(7,491)	(8,831)	(59,718)
Per share – basic and diluted	**0.24**	(0.12)	(0.15)	(0.98)
Cash flow from (used in) operating activities	**(1,104)**	(2,538)	(2,777)	(3,114)
Adjusted funds flow(1)	**1,240**	(2,098)	(3,328)	(3,601)
Per share – basic and diluted	**0.02**	(0.03)	(0.05)	(0.06)
Capital expenditures	**466**	251	(11)	5,233
Net payments (proceeds) on acquisitions and dispositions	**–**	133	(34,661)	–
Net capital expenditures	**466**	384	(34,672)	5,233
Common shares *(thousands)*				
Weighted average – basic and diluted	**61,266**	61,200	60,776	60,674
Operating				
Daily average production				
Conventional natural gas *(MMcf/d)*	**19.5**	16.3	16.9	33.3
Heavy crude oil *(bbl/d)*	**1,241**	1,193	573	1,320
NGL *(bbl/d)*	**237**	273	268	606
Total *(boe/d)*	**4,730**	4,188	3,662	7,479
Average prices				
Realized natural gas price *($/Mcf)*(2)	**1.46**	0.06	0.28	1.16
Realized oil price *($/bbl)*(2)	**52.60**	55.71	67.56	32.60
Realized NGL price *($/bbl)*(2)	**38.03**	28.09	17.35	36.48

($ thousands, except where noted)	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Financial				
Oil and natural gas revenue	15,830	17,097	19,235	22,199
Net loss	(32,498)	(20,349)	(36,276)	(4,892)
Per share – basic and diluted	(0.54)	(0.34)	(0.60)	(0.08)
Cash flow from operating activities	(1,290)	5,509	4,295	9,292
Adjusted funds flow(1)	340	4,183	3,649	6,362
Per share – basic	0.01	0.07	0.06	0.11
Capital expenditures	1,995	4,506	5,200	1,238
Net payments (proceeds) on acquisitions and dispositions	–	–	–	–
Net capital expenditures	1,995	4,506	5,200	1,238
Common shares (*thousands*)				
Weighted average – basic and diluted	60,444	60,317	60,154	60,111
Operating				
Daily average production				
Conventional natural gas (*MMcf/d*)	36.6	38.2	44.5	50.0
Heavy crude oil (*bbl/d*)	1,275	1,292	1,207	1,121
NGL (*bbl/d*)	606	731	754	785
Total (*boe/d*)	7,991	8,383	9,370	10,240
Average prices				
Realized natural gas price (*$/Mcf*)(2)	2.00	3.13	2.25	3.54
Realized oil price (*$/bbl*)(2)	43.85	44.31	50.01	41.12
Realized NGL price (*$/bbl*)(2)	43.93	37.34	51.34	32.16

(1) See "Non-GAAP measures" in this MD&A.
(2) Realized natural gas, oil and NGL prices include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.

The Company's oil and natural gas revenue, net income (loss), cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Conventional natural gas production levels decreased during 2019 and 2020 due to natural declines and reduced capital expenditures in response to depressed and volatile AECO natural gas prices. The disposition of a 50% working interest in the East Edson property which closed on April 1, 2020 for net cash consideration of $34.8 million and an eight well carried capital commitment, further reduced conventional natural gas production in the second and third quarters of 2020, before increasing slightly in the fourth quarter as five (2.5 net) new carried interest wells have been tied-in to production. Oil-focused capital expenditures increased beginning in the second quarter of 2019, as improved oil prices and differentials supported investment. In response to the significant decline in global oil prices which began in March 2020, oil-focused capital expenditures and high-cost production was temporarily suspended, pending a recovery of oil prices, and oil focused hedging gains were locked-in. Heavy crude oil production was restarted mid-way through the second quarter, following the recovery of oil prices.

For the year ended December 31, 2020, the Company's net loss was impacted by net impairment charges of $42.5 million (Q4 2020 – $18.0 million impairment reversal; Q1 2020 – $60.5 million impairment charge), compared to total impairments of $47.1 million in the prior year (Q2 2019 – $22.6 million; Q4 2019 – $24.5 million). Perpetual also recognized $1.5 million of restructuring costs during the third quarter of 2019.

Commodity price risk management and sales obligations

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in adjusted funds flow by mitigating the effect of commodity price volatility. Physical forward sales contracts and financial derivatives are used to manage the balance sheet, to lock in economics on capital programs and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange derivatives and physical or financial derivatives related to the differential between natural gas prices at the AECO and NYMEX trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized revenue. Diversification of markets is a further risk management strategy employed by the Company.

The following tables provide a summary of open commodity price risk management contracts outstanding at February 24, 2021:

Heavy crude oil

The following tables provide a summary of physical fixed price WTI, WCS and WTI-WCS basis differential contracts which settle in US$:

Term	**Volumes sold (bought)** ***(bbl/d)***	**WTI** ***(US$/bbl)***	**Market prices** ***(US$/bbl)***[1]
January 2021	203	44.05	52.10
January 2021 – March 2021	203	41.50	58.05
April 2021 – June 2021	203	53.90	62.31

Term	**Volumes sold (bought)** ***(bbl/d)***	**WTI-WCS differential** ***(US$/bbl)***	**Market prices** ***(US$/bbl)***[1]
April 2021 – June 2021	203	(11.90)	(11.27)
April 2021 – September 2021	203	(14.20)	(11.23)
January 2021 – December 2021	310	(13.25)	(11.82)

(1) Market prices for January and February are based on settled WTI-WCS differential prices. Market prices for subsequent months are based on forward WTI-WCS differential prices as of market close on February 24, 2021.

Term	**Volumes sold (bought)** ***(bbl/d)***	**WCS** ***(US$/bbl)***	**Market prices** ***(US$/bbl)***[1]
January 2021	203	33.70	40.04
February 2021	337	31.05	44.96
March 2021	406	32.75	51.74

Conventional natural gas sales obligations

In the third quarter of 2020, the Company reduced its fixed volume obligations by 30,000 MMBtu/d for the period commencing November 1, 2020 and ending on October 31, 2021 in consideration for the payment of $1.0 million over the term of the associated contract volumes. In the fourth quarter of 2020, the Company reduced its fixed volume obligation by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 in consideration for the receipt of $0.5 million over the term of the associated contract volumes. For the year ended December 31, 2020, these modifications have been recognized as a net realized loss on derivatives of $0.5 million in the consolidated statements of loss and comprehensive loss.

In February 2021, the Company's 10,000 MMBtu/d market diversification contract obligations were eliminated for the period of April 1, 2021 to October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes.

Conventional natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations and priced at daily index prices at each of the market price points, less transportation costs from AECO to each market price point as detailed below.

Market/Pricing Point	**November 1, 2020 to March 31, 2021 Daily sales volume** ***(MMBtu/d)***	**November 1, 2021 to October 31, 2022 Daily sales volume** ***(MMBtu/d)***	**November 1, 2022 to October 31, 2024 Daily sales volume** ***(MMBtu/d)***
Chicago	4,000	12,200	–
Malin	–	–	15,000
Dawn	6,000	8,000	15,000
Michcon	–	5,200	–
Emerson	–	–	10,000
Total sales volume obligation	**10,000**	**25,400**	**40,000**

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2020**	2019	2018[4]
Financial			
Oil and natural gas revenue	**29,486**	74,361	86,128
Net income (loss)	**(61,597)**	(94,015)	(20,380)
Per share – basic and diluted[1]	**(1.01)**	(1.56)	(0.34)
Cash flow from (used in) operating activities	**(9,533)**	17,806	31,525
Adjusted funds flow	**(7,787)**	14,534	30,155
Per share[1][2]	**(0.13)**	0.24	0.50
Total assets	**140,454**	241,148	335,089
Total long-term liabilities	**68,722**	118,061	101,870
Revolving bank debt	**17,495**	47,552	42,561
Senior notes, principal amount	**33,580**	33,580	32,490
Term loan, principal amount	**46,823**	45,000	45,000
TOU share margin demand loan, principal amount	**–**	100	14,144
TOU share investment	**–**	(15,220)	(28,132)
Net working capital deficiency	**7,099**	7,068	6,543
Total net debt	**104,997**	118,080	112,606
Net capital expenditures			
Capital expenditures	**5,939**	12,939	26,888
Net proceeds on acquisitions and dispositions	**(34,528)**	–	(3,030)
Net capital expenditures	**(28,589)**	12,939	23,858
Common shares (*thousands*)			
End of period[3]	**61,305**	60,513	60,240
Weighted average – basic and diluted	**61,013**	60,258	60,039
Operating			
Daily average production			
Conventional natural gas (*MMcf/d*)	**21.5**	42.3	52.6
Heavy crude oil (*bbl/d*)	**1,082**	1,224	1,050
NGL (*bbl/d*)	**346**	719	774
Total average production (*boe/d*)	**5,012**	8,988	10,594
Average prices			
Realized natural gas price *($/Mcf)*	**0.85**	2.77	3.05
Realized oil price *($/bbl)*	**49.37**	44.87	40.62
NGL price (*$/bbl*)	**31.40**	41.01	52.96
Wells drilled			
Conventional natural gas – gross (net)	**5 (2.5)**	– (–)	1 (1.0)
Heavy crude oil – gross (net)	**4 (4.0)**	5 (5.0)	6 (6.0)
Total – gross (net)	**9 (6.5)**	5 (5.0)	7 (7.0)

(1) Based on weighted average common shares outstanding for the year.
(2) See "Non-GAAP measures" in this MD&A.
(3) Reduced by shares held in trust (2020 – 556; 2019 – 801; 2018 – 661). See "Note 16 to the Consolidated Financial Statements".
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

CHANGES IN ACCOUNTING POLICIES

Government grants

Government grants are recognized when there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as an expense reduction in the period in which the costs are incurred. Government grants related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed.

For the year ended December 31, 2020, the Company received government grants through the Canada Emergency Wage Subsidy and Canada Emergency Rent Subsidy of $1.3 million. These grants were recognized as a reduction to G&A and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). For the year ended December 31, 2020, the Company also received government grants through the Alberta Site Rehabilitation program of $0.8 million to fund approved abandonment and remediation projects. These grants were recognized as "Other income" in the consolidated statements of loss and comprehensive loss. Associated expenditures were recorded as a reduction to decommissioning obligations on the consolidated statements of financial position.

ACCOUNTING PRONOUNCEMENTS

Amendments to IFRS 3 "Business Combinations"

On January 1, 2020, the Company adopted the amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities in determining whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant's perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test.

No business combinations were completed during the year ended December 31, 2020.

CORPORATE GOVERNANCE

The Corporation is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange and the Canadian provincial securities commissions, has a different set of rules pertaining to corporate governance. The Corporation fully conforms to the rules of the governing bodies under which it operates.

RISK FACTORS

The Corporation is exposed to business risks that are inherent in the oil and gas industry, as well as those governed by the individual nature of Perpetual's operations. Risks impacting the business which influence controls and management of the Corporation include, but are not limited to, the following:

- geological and engineering risks;
- the uncertainty of discovering commercial quantities of new reserves;
- commodity prices, interest rate and foreign exchange risks;
- competition; and
- changes to government regulations including shut-in of gas over bitumen assets, royalty regimes and tax legislation.

Perpetual manages these risks by:

- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Corporation;
- prudent operation of oil and natural gas properties;
- employing risk management instruments and policies to manage exposure to volatility of commodity prices, interest rates and foreign exchange rates;
- maintaining a flexible financial position;
- maintaining strict environmental, safety and health practices; and
- active participation with industry organizations to monitor and influence changes in government regulations and policies.

A complete discussion of risk factors is included in the Corporation's 2020 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Perpetual's CEO and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

Disclosure controls and procedures

The DC&P have been designed to provide reasonable assurance that material information relating to Perpetual is made known to the CEO and CFO by others, and that information required to be disclosed by Perpetual in its annual filings, interim filing or other reports is filed or submitted by Perpetual under securities legislation.

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2020, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

Management is responsible for establishing and maintaining adequate ICOFR, which is a process designed by, or under the supervision of, the CEO and CFO, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2020 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2020, the internal controls over financial reporting were designed and operating effectively.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on October 1, 2020 and ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2020 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING ESTIMATES

Perpetual makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements. Critical accounting estimates include proved and probable oil and gas reserves and the related cash flows, sales value of undeveloped lands, derivative financial instruments, provisions for decommissioning and royalty obligations and share-based payments, income taxes, and the amount and likelihood of contingent liabilities. Critical accounting estimates are based on assumptions and data including:

- Estimation of recoverable proved and probable oil and gas reserves and the related future cash flows from reserves;
- Forecasted oil and gas commodity prices;
- Forecasted operating costs, royalty costs and future development costs;
- Sales value of undeveloped lands;
- Geological interpretations, success or failure of exploration activities, and Perpetual's plans with respect to property and financial ability to hold the property;
- Risk free interest rates, inflation rates, and volatility in stock prices and oil and gas commodity prices; and
- Estimation of future abandonment and reclamation costs and timelines.

A change in a critical accounting estimate can have a significant effect on net loss, including their impact on the depletion rate, provisions, impairments, and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2020.

FORWARD-LOOKING INFORMATION AND STATEMENTS: Certain information and statements contained in this MD&A including management's assessment of future plans and operations, and including the information contained under the headings "Future Operations" and "Outlook" may constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to future performance. All statements other than statements of historical fact may be forward-looking information and statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the potential outcome of the Sequoia Litigation, the ability to extend the Credit Facility or to refinance its Term Loan on favorable terms; the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for conventional natural gas, NGL and heavy crude oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and financial contracts to be employed, and the value of financial forward natural gas, oil and other risk management contracts; net income (loss) and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; production and operating, general and administrative ("G&A"), and other expenses; the costs and timing of future abandonment and reclamation, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base; the Corporation's acquisition and disposition strategy and the existence of acquisition and disposition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital expenditure program; expected compliance with credit facility and Term Loan covenants in 2021 and 2022; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; adjusted funds flow; ability to fund exploration and development; the corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the effect of future accounting pronouncements and their impact on the Corporation's financial results; future income tax and its effect on adjusted funds flow; intentions with respect to preservation of tax pools and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities, construction and waterflood plans, and the effect thereof; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management including future changes in the structure of business operations and debt reduction initiatives; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

Various assumptions were used in drawing the conclusions or making the forecasts and projections in the forward-looking information contained in this MD&A, which assumptions are based on management's analysis of historical trends, experience, current conditions and expected future developments pertaining to Perpetual and the industry in which it operates as well as certain assumptions regarding the matters outlined above. Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, including, without limitation, the impact of COVID-19 as further described below, which could cause actual results to vary and in some instances to differ materially from those anticipated by Perpetual and described in the forward-looking information contained in this MD&A. In particular and without limitation of the foregoing, the recent outbreak of COVID-19 has had a negative impact on global financial conditions. Perpetual cannot accurately predict the impact that COVID-19 will have on its ability to execute its business plans in response to government public health efforts to contain COVID-19 and to obtain financing or third parties' ability to meet their contractual obligations with Perpetual including due to uncertainties relating to the ultimate geographic spread of the virus, the severity of the disease, the duration of the outbreak, and the length of travel and quarantine restrictions imposed by governments of affected jurisdictions; and the current and future demand for oil and gas. In the event that the prevalence of COVID-19 continues to increase (or fears in respect of COVID-19 continue to increase), governments may increase regulations and restrictions regarding the flow of labour or products, and travel bans, and Perpetual's operations, service providers and customers, and ability to advance its business plan or carry out its top strategic priorities, could be adversely affected. In particular, should any employees, consultants or other service providers of Perpetual become infected with COVID-19 or similar pathogens, it could have a material negative impact on Perpetual's operations, prospects, business, financial condition and results of operations. Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Perpetual's Annual Information Form and MD&A for the year ended December 31, 2020 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at Perpetual's website (www.perpetualenergyinc.com).

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: volatility in market prices for oil and natural gas products; supply and demand regarding Perpetual's products; risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties; reliance on industry partners; uncertainties or inaccuracies associated with estimating reserves volumes; competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs; incorrect assessments of the value of acquisitions; increased debt levels or debt service requirements; industry conditions including fluctuations in the price of natural gas and related commodities; royalties payable in respect of Perpetual's production; governmental regulation of the oil and gas industry, including environmental regulation; fluctuation in foreign exchange or interest rates; the need to obtain required approvals from regulatory authorities; changes in laws applicable to the Corporation, royalty rates, or other regulatory matters; general economic conditions in Canada, the United States and globally; stock market volatility and market valuations; limited, unfavorable, or a lack of access to capital markets, and certain other risks detailed from time to time in Perpetual's public disclosure documents. In addition, defence costs of legal claims can be substantial, even with respect to claims that have no merit and due to the inherent uncertainty of the litigation process, the resolution of the legal proceedings to which the Company has become subject could have a material effect on the Company's financial position and results of operations.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is released, and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

OIL AND GAS ADVISORIES

This MD&A contains metrics commonly used in the oil and natural gas industry, such as "finding and development" costs or "F&D" costs. These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this MD&A to provide readers with additional measures to evaluate Perpetual's performance, however, such measures are not reliable indicators of Perpetual's future performance and future performance may not compare to Perpetual's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders and investors with measures to compare Perpetual's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

F&D costs are calculated on a per boe basis by dividing the aggregate of the change in FDC from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category. F&D costs take into account reserve revisions during the year on a per boe basis. The aggregate of the F&D costs incurred in the financial year and changes during that year in estimated FDC generally will not reflect total F&D costs related to reserves additions for that year.