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 three and six months ended June 30, 2019 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 unaudited condensed interim consolidated financial statements and accompanying notes for the three and six months ended June 30, 2019 as well as the audited consolidated financial statements and accompanying notes for the years ended December 31, 2018 and 2017. The MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2018, as disclosure which is unchanged from the December 31, 2018 MD&A has not been duplicated herein. 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"). The Corporation adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section of this MD&A for further information. 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 July 31, 2019.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual operates a diversified asset portfolio, including liquids-rich natural gas assets in the deep basin of west central Alberta, heavy oil and shallow natural gas in eastern Alberta and undeveloped oil sands 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", "gas over bitumen revenue, net of payments", "net working capital deficiency (surplus)", "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: 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 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 also deducted the change in 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 surplus office lease obligations, which management considers to not be related to cash flow from operating activities.

Adjusted funds flow per share is calculated using the same 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 June 30,		Six months ended June 30,	
($ thousands, except per share and per boe amounts)	**2019**	2018[1]	**2019**	2018[1]
Net cash flows from operating activities	**4,295**	8,435	**13,587**	19,633
Change in non-cash working capital	**(716)**	(731)	**(3,557)**	(3,127)
Decommissioning obligations settled	**360**	353	**666**	906
Change in gas over bitumen royalty financing	**(290)**	(260)	**(685)**	(699)
Payments of restructuring costs	**–**	50	**–**	235
Adjusted funds flow	**3,649**	7,847	**10,011**	16,948
Adjusted funds flow per share	**0.06**	0.13	**0.17**	0.28
Adjusted funds flow per boe	**4.28**	8.12	**5.64**	8.02

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach, resulting in an increase in net cash flows from operating activities and adjusted funds flow of $0.1 million for the three and six month periods ended June 30, 2019. Comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Available Liquidity: Available Liquidity is defined as Perpetual's reserve-based credit facility borrowing limit (the "Borrowing Limit"), plus the fair value of the Tourmaline Oil Corp. ("TOU") share investment, less borrowings and letters of credit issued under the reserve-based credit facility (the "Credit Facility") and the TOU share margin demand loan. 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: Management believes that cash costs assist management and investors in assessing Perpetual's efficiency and overall cost structure. 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.

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except per boe amounts)	**2019**	2018(1)	**2019**	2018(1)
Royalties	**2,464**	2,590	**5,640**	5,653
Production and operating	**4,911**	4,304	**10,231**	9,076
Transportation	**1,635**	1,546	**3,166**	2,989
General and administrative	**3,177**	3,130	**6,648**	6,441
Cash finance expense	**2,250**	2,143	**4,560**	4,258
Cash costs	**14,437**	13,713	**30,245**	28,417
Cash costs per boe	**16.93**	14.19	**17.05**	13.45

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

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 but excludes any realized gains (losses) resulting from marketing contracts associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition") to Sequoia Resources Corp. ("Sequoia"). Realized revenue, including foreign exchange and the market diversification contract, is used by management to calculate the Corporation's net realized commodity prices, taking into account 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 commodity price.

Gas over bitumen revenue, net of payments: Gas over bitumen revenue, net of payments, includes gas over bitumen royalty credits less monthly payments on the gas over bitumen royalty financing. This is used by management to calculate the Corporation's net realized gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty credits.

Operating netback: Perpetual considers operating netback to be an important performance measure as it demonstrates its profitability relative to current commodity prices. 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 for the period. Operating netback on a per boe basis can vary significantly for each of the Company's operating areas.

Net working capital deficiency (surplus): Net working capital deficiency (surplus) includes total current assets and current liabilities excluding short-term derivative assets and liabilities related to the Corporation's risk management activities, current portion of gas over bitumen royalty financing, TOU share investment, TOU share margin demand loan, 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 (surplus). 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 fair 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. Enterprise value is not intended to represent the total funds from equity and debt received by the Corporation upon issuance.

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 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 natural gas and crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl.

SECOND QUARTER 2019 HIGHLIGHTS

Natural gas prices in Alberta continue to remain disconnected from other North American markets, with the AECO Daily Index price averaging $0.98/GJ in the second quarter of 2019 compared to an average NYMEX price of US$2.64/MMBtu. Perpetual's market diversification contract enabled the Company to sell approximately 80% of its natural gas production (adjusted for heat content) to markets priced at five pricing hubs outside of Alberta, and provided an 82% uplift over average AECO Daily Index prices during the second quarter (Q2 2018 – 90%).

Exploration and development spending for the second quarter of 2019 was $5.2 million, of which 91% was directed towards the drilling and completion of three (3.0 net) heavy oil wells and a re-entry to add two additional laterals to an existing oil well at Mannville. The Company accelerated its Mannville heavy oil drilling program initially planned for the third quarter of 2019 to take advantage of dry early spring lease conditions. The four wells were brought on-stream late in the second quarter and have ramped up to approximately 300 boe/d at the end of July. The Eastern Alberta heavy oil program has continued into the third quarter, with two (2.0 net) exploratory six-leg multi-lateral wells currently drilling in the Ukalta area. An additional $0.4 million was spent in West Central Alberta and was directed towards compressor optimization work and non-operated facility turnaround costs at Rosevear.

Production averaged 9,370 boe/d in the second quarter of 2019, down 12% from the comparable period in 2018. The decrease was driven by natural declines resulting from limited capital investment on the Company's natural gas assets during 2018 and the first half of 2019 to preserve value during this period of depressed natural gas pricing in Alberta. In addition, Perpetual voluntarily shut-in an average 175 boe/d of East Edson production (2% of second quarter production) during the quarter to take advantage of short-term situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.03/Mcf while retaining reserves for future production. Heavy oil production in Eastern Alberta grew 27% relative to the second quarter of 2018 and 7% from first quarter 2019 levels, driven by positive results from heavy oil focused drilling and waterflood investment during the second half of 2018 and first half of 2019.

Realized revenue was $21.26/boe in the second quarter of 2019, 6% lower than the comparative period of 2018 ($22.58/boe). The decrease was due largely to the 14% decrease in Perpetual's realized natural gas price to $2.25/Mcf, combined with declines in realized crude oil and NGL prices of 6% and 16% respectively, despite a higher proportion of oil and NGL in the production mix (Q2 2019 – 21%; Q2 2018 – 17%). Compared to the prior year period, lower realized natural gas prices were the result of a 6% and 13% decrease in the NYMEX and AECO Daily Index prices, respectively. During the second quarter, the Company's market diversification contract contributed $3.4 million of incremental revenue ($0.84/Mcf) over the AECO Daily Index price (Q2 2018 - $5.1 million and $1.06/Mcf). The market diversification contract is expected to continue to provide higher natural gas pricing and enhanced risk management through future periods of volatile natural gas prices in Western Canada related to market access constraints.

Cash costs were $16.93/boe in the second quarter of 2019, up 19% compared to the prior year period due to the impact of a 12% decrease in production coupled with a 5% increase in cash costs. Production and operating costs were up by $0.6 million, primarily in Eastern Alberta with the 27% (251 bbl/d) increase in higher cost heavy oil production.

The net loss for the second quarter of 2019 was $36.3 million ($0.60/share), compared to a net loss of $1.3 million ($0.02/share) in the comparative period of 2018. The increase in net loss from the prior year period was due to an impairment charge of $22.6 million recognized during the second quarter of 2019, combined with the $6.6 million decrease in the fair value of the TOU share investment compared to an increase of $2.8 million in the comparative period of 2018. See the "Impairment" section of this MD&A for additional impairment charge details. The adoption of IFRS 16 in the first quarter resulted in a nominal change in net loss. See "Recently adopted accounting pronouncements" section of this MD&A.

Cash flow from operating activities in the second quarter of 2019 was $4.3 million ($0.07/share), down $4.1 million from the prior year period of $8.4 million ($0.14/share) due to the impact of the 12% decrease in production, as the impairment loss and changes in fair value of the TOU share investment that impacted net loss did not impact cash flow from operating activities.

Adjusted funds flow in the second quarter of 2019 was $3.6 million ($0.06/share), down $4.2 million (53%) from the prior year period of $7.8 million ($0.13/share) due to lower cash flow from operating activities. On a unit-of-production basis, adjusted funds flow was $4.28/boe in the second quarter of 2019, down 47% from the prior year period of $8.12/boe due to the combined impact of lower production and higher cash costs.

On March 27, 2019, the $55 million revolving bank debt Borrowing Limit was confirmed by the Company's lenders and the maturity was extended to November 30, 2020. The Credit Facility will revolve until May 31, 2020 and may be extended for a further 364-day period subject to approval by the Company's lenders. If not extended, the Credit Facility will cease to revolve and all outstanding advances will be repayable on November 30, 2020. The next Borrowing Limit redetermination is scheduled on or prior to November 30, 2019.

On June 11, 2019, the Company successfully completed the early redemption of all of the $14.6 million 8.75% senior unsecured notes due July 23, 2019 (the "2019 Senior Notes"). Pursuant to the early redemption, Perpetual issued $15.7 million of 8.75% senior unsecured notes due January 23, 2022 (the "2022 Senior Notes") to fully redeem the 2019 Senior Notes. After giving effect to the senior note refinancing, there are $33.6 million 2022 Senior Notes outstanding, comprised of $17.9 million 2022 Senior Notes previously outstanding and the $15.7 million 2022 Senior Notes issued as consideration to redeem the 2019 Senior Notes.

On August 3, 2018, the Company received a Statement of Claim related to the Company's disposition of certain shallow gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Shallow Gas Disposition") that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual (the "Sequoia Litigation"). Perpetual's Application for Summary Dismissal of the Sequoia Litigation was heard during the fourth quarter of 2018. There were no significant developments during the second quarter of 2019 concerning this litigation. The Court's decision is scheduled to be received orally in court on August 15, 2019. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements. See "Liquidity and Capital Resources" section of this MD&A for additional details.

OUTLOOK

Perpetual has reduced its 2019 capital expenditure and adjusted funds flow guidance from a range of $21 to $25 million and $22 to $27 million respectively, provided in a press release dated May 8, 2019 (the "Previous Guidance") to $18 to $21 million, due to the 15% decline in NYMEX natural gas price expectations for the remainder of 2019. Approximately 80% of Perpetual's natural gas volumes are priced in NYMEX based markets outside of Alberta. The Company continues to anticipate spending 50% of the 2019 capital program in Eastern Alberta targeting heavy oil development. The remaining capital expenditures are planned for East Edson in the fourth quarter, developing liquids-rich natural gas reserves in the Wilrich formation if AECO natural gas prices support investment, or alternatively, will be directed to an expanded heavy oil drilling program. Annual abandonment and reclamation spending of $1.5 to $2.0 million to address decommissioning obligations associated with non-producing wells is expected to provide future surface lease rental and property tax expense reductions, while maintaining regulatory compliance.

Forecast capital activity in Eastern Alberta for the second half of 2019 includes the drilling and completion of two exploratory (2.0 net) multi-lateral heavy oil wells in July. As a result of the drilling program, heavy oil production is forecast to increase by 20% to 30% in the second half of 2019 over first half levels.

At East Edson, the Company has budgeted a two (2.0 net) well drilling program in the fourth quarter of 2019. The two wells will be monobore, extended reach horizontal ("ERH") wells with approximately 2,500 meters of lateral length to optimize the drilling and completion design. The planned drilling will not have a material impact on production in 2019, as new wells are forecast to come on-stream late in the year when AECO natural gas prices are expected to be stronger due to winter heating demand. Natural declines and capital spending deferrals to late 2019 result in lower forecast 2019 production in East Edson with an average of 7,000 to 7,200 boe/d (10% oil and NGL). Despite reduced production in East Edson and a substantially fixed operating cost base, operating costs are forecast to remain low in 2019 at less than $3.25/boe.

The table below summarizes actual and anticipated capital spending and drilling activities for the first and second half of 2019.

2019 Exploration and Development Forecast Capital Expenditures

	First half 2019 *($ millions)*	# of wells *(gross/net)*	Second half 2019 *($ millions)*	# of wells *(gross/net)*
West Central liquids-rich gas	1.1	0/0.0	8.4	2/2.0
Eastern Alberta	5.3	3/3.0[(2)]	2.9	2/2.0
Total[(1)]	**6.4**	**3/3.0**[(2)]	**11.3**	**4/4.0**

(1) Excludes budgeted abandonment and reclamation spending of $1.5 to $2.0 million in 2019 (2019 year to date – $0.7 million).
(2) Excludes the re-entry of one existing well bore in Mannville.

Perpetual is managing the 2019 capital program to be funded by adjusted funds flow. Average production of 9,200 to 9,500 boe/d in 2019 is close to Previous Guidance, with oil and NGL production growing to represent approximately 20% to 24% of the production mix. Natural declines and heavy oil focused investment is anticipated to result in an 11% year-over-year reduction in average daily production relative to 2018, but includes a 27% increase in heavy oil production. The Company expects to exit the year at approximately 10,500 boe/d as natural gas and NGL production ramps up again driven by fourth quarter capital spending targeting seasonal natural gas price optimization. The Company may continue to voluntarily shut-in natural gas production in response to weak AECO daily price conditions that may arise during the second half of 2019 to preserve reserves and purchase natural gas to satisfy existing sales obligations at attractive cash margins.

Cash costs of $17.00 to $18.00/boe continue to be forecast for 2019, up approximately 13% to 16% from 2018 due to the impact of lower forecast 2019 production on a substantially fixed operating cost base. Increased heavy oil production in the second half of 2019, which is higher cost compared to the West Central deep basin liquids-rich gas operation, is expected to contribute to increased cash costs per boe in the second half of 2019.

Perpetual has diversified its commodity and natural gas pricing point exposure (net of royalties) away from AECO as detailed below:

Market/Pricing Point

Natural gas	**Estimated 2019 Exposure**
AECO[(1)]	–
AECO - fixed price[(2)]	9%
Empress	7%
Dawn	14%
Michcon	9%
Chicago	21%
Malin	19%
Total natural gas	79%
NGL - Condensate[(1)]	3%
NGL - Other[(1)]	2%
Crude oil[(1)(2)]	16%
Total forecast production, net of royalties	100%

(1) Net of royalties.
(2) See “Commodity price risk management and sales obligations” section of this MD&A for details.

2019 annual guidance assumptions are as follows:

	Current Guidance	Previous Guidance
2019 exploration and development expenditures *($ millions)*	**$18 - $21**	$21 - $25
2019 cash costs *($/boe)*	**$17.00 - $18.00**	$17.00 - $18.00
2019 average daily production *(boe/d)*	**9,200 - 9,500**	9,200 - 9,600
2019 average production mix *(% oil and NGL)*	**20% - 24%**	20% - 24%
2019 adjusted funds flow *($ millions)*	**$18 - $21**	$22 - $27
2019 adjusted funds flow *($/share)*	**$0.30 - $0.34**	$0.36 - $0.44

Commodity price assumptions reflect forward market price levels as follows:

Market prices[(1)]	**Current Guidance**	Previous Guidance
2019 average NYMEX natural gas price *(US$/MMBtu)*	**$2.68**	$2.91
2019 average West Texas Intermediate (“WTI”) oil price *(US$/bbl)*	**$58.67**	$60.65
2019 average Western Canadian Select (“WCS”) differential *(US$/bbl)*	**($14.18)**	($14.26)
2019 average exchange rate *(US$1.00 = Cdn$)*	**1.32**	1.33

(1) Reflects settled and forward market prices.

Year-end 2019 net debt (net of the estimated market value of the Company's TOU share investment of approximately $28 million), is forecast at $114 - $119 million, up $7 million from Previous Guidance due to the decrease in the TOU share price during the second quarter. Current guidance is based on the following assumptions:

- Net debt at June 30, 2019 of $112.5 million;
- Forecast adjusted funds flow for the remainder of 2019 of $7 to $10 million;
- Forecast capital spending for the remainder of 2019 of $10 to $13 million; and
- Forecast decommissioning expenditures for the remainder of 2019 of $0.8 to $1.3 million.

The following sensitivities can be applied to estimate changes to 2019 annualized cash flow from operating activities and adjusted funds flow, assuming no change in differentials to Perpetual's market pricing points:

- For every US$0.25/MMBtu increase or decrease in the 2019 average NYMEX Daily Index price, annualized adjusted funds flow increases or decreases by $4.8 million;
- For every US$2.50/bbl increase or decrease in the 2019 average WTI light oil price, annualized adjusted funds flow increases or decreases by $1.5 million;
- For every 2.5 MMcf/d increase or decrease in 2019 average natural gas production, annualized adjusted funds flow increases or decreases by $1.5 million;
- For every 100 bbl/d increase or decrease in 2019 average crude oil and NGL production, annualized adjusted funds flow increases or decreases by $1.6 million; and
- For every $0.05 increase or decrease in the 2019 average Cdn$/US$ exchange rate, annualized adjusted funds flow increases or decreases by $1.5 million.

SECOND QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
Exploration and development	**5,170**	1,737	**6,380**	16,584
Corporate assets	**30**	294	**58**	344
Capital expenditures	**5,200**	2,031	**6,438**	16,928
Acquisitions	**–**	610	**–**	610
Net proceeds on dispositions	**–**	(7,622)	**–**	(6,696)
Total	**5,200**	(4,981)	**6,438**	10,842

Exploration and development spending by area

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
West Central	**445**	307	**1,113**	9,249
Eastern Alberta	**4,725**	1,430	**5,267**	7,335
Total	**5,170**	1,737	**6,380**	16,584

Wells drilled by area

	Three months ended June 30,		Six months ended June 30,	
(gross/net)	**2019**	2018	**2019**	2018
West Central	**-/-**	-/-	**-/-**	1/1.0
Eastern Alberta	**3/3.0[1]**	-/-	**3/3.0[1]**	3/3.0
Total	**3/3.0[1]**	-/-	**3/3.0[1]**	4/4.0

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

Perpetual's exploration and development spending in the second quarter of 2019 was $5.2 million, above Previous Guidance as dry conditions in Mannville allowed for an accelerated start to the summer drilling program.

In the second quarter of 2019, capital spending in Eastern Alberta was $4.7 million, $3.3 million higher than the comparative period in 2018. Capital activity included the drilling and completion of three (3.0 net) single leg horizontal heavy oil wells, and one re-entry to add two additional lateral legs to an existing heavy oil well at Mannville. Spending also included the installation of automated leak detection monitoring equipment at several water transfer and water injection pipelines in the Mannville area. The drilling program has continued into the third quarter, with two (2.0 net) exploratory six-leg multi-lateral wells currently drilling in the Ukalta area.

Spending at the East Edson property in West Central Alberta was $0.4 million and was directed towards compressor optimization work and non-operated facility turnaround costs at the Rosevear plant.

For the six months ended June 30, 2019, exploration and development spending was $6.4 million, 62% lower than the comparative period of 2018. In addition to the second quarter activity, spending in West Central during the first quarter was primarily directed towards the installation of field compression equipment and a sweetening tower to restore several higher liquids ratio natural gas wells back to production.

Dispositions

Proceeds (payments) on dispositions

($ thousands)	Three months ended June 30, **2019**	2018	Six months ended June 30, **2019**	2018
Proceeds on dispositions of oil and gas properties	**–**	12,149	**–**	12,152
Payments on retained shallow gas marketing arrangements[1]	**–**	(4,527)	**–**	(5,456)
Net proceeds on dispositions	**–**	7,622	**–**	6,696

Loss on dispositions

($ thousands)	Three months ended June 30, **2019**	2018	Six months ended June 30, **2019**	2018
Proceeds on dispositions of oil and gas properties	**–**	12,149	**–**	12,152
Carrying amount of PP&E disposed	**–**	(848)	**–**	(848)
Carrying amount of E&E disposed	**–**	(10,947)	**–**	(10,947)
Carrying amount of ARO disposed	**–**	380	**–**	380
Gain on dispositions of oil and gas properties	**–**	734	**–**	737
Realized loss on retained shallow gas marketing arrangements[1]	**–**	–	**–**	(874)
Gain (loss) on dispositions	**–**	734	**–**	(137)

(1) Related to the Shallow Gas Disposition.

The Company did not complete any acquisitions or dispositions during the three or six months ended June 30, 2019. Dispositions during the three and six months ended June 30, 2018 included the sale of non-core royalty interests and exploration and evaluation properties for gross proceeds of $12.2 million, resulting in a net gain on oil and gas properties of $0.7 million. Payments of $4.5 million were made during the second quarter of 2018 ($5.5 million for the six months ended June 30, 2018) related to marketing contracts associated with the Shallow Gas Disposition. The retained marketing contracts expired in the third quarter of 2018.

Expenditures on decommissioning obligations

During the three months ended June 30, 2019, Perpetual spent $0.4 million (Q2 2018 – $0.4 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, four reclamation certificates were received from the AER during the second quarter of 2019 (Q2 2018 – five reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. For the six months ended June 30, 2019, Perpetual spent $0.7 million (2018 – $0.9 million) on abandonment and reclamation projects and received eight reclamation certificates, compared to 13 in the prior year period. Expenditures of up to $2.0 million are forecast in 2019, focused in Eastern Alberta under the Alberta Energy Regulator's ("AER") recently adopted area-based closure approach. The Company's combined ratio of deemed assets to deemed liabilities as per the AER's Licensee Liability Rating was 4.5 at June 30, 2019.

Operating netbacks

The following table highlights Perpetual's operating netbacks for the three and six months ended June 30, 2019 and 2018:

	Three months ended June 30, 2019			Three months ended June 30, 2018[3]		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue[1]	**11,640**	**7,595**	**19,235**	14,818	5,956	20,774
Realized gains (losses) on derivatives[2]	**–**	**–**	**(1,110)**	–	–	1,048
Royalties	**(1,423)**	**(1,041)**	**(2,464)**	(1,999)	(591)	(2,590)
Production and operating expenses	**(2,003)**	**(2,908)**	**(4,911)**	(1,794)	(2,510)	(4,304)
Transportation costs	**(1,097)**	**(538)**	**(1,635)**	(1,196)	(350)	(1,546)
Total operating netback	**7,117**	**3,108**	**9,115**	9,829	2,505	13,382

	Six months ended June 30, 2019			Six months ended June 30, 2018[3]		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue[1]	**27,834**	**13,600**	**41,434**	33,908	10,206	44,114
Realized gains (losses) on derivatives[2]	**–**	**–**	**(968)**	–	–	1,739
Royalties	**(4,025)**	**(1,615)**	**(5,640)**	(4,578)	(1,075)	(5,653)
Production and operating expenses	**(3,998)**	**(6,233)**	**(10,231)**	(3,837)	(5,239)	(9,076)
Transportation costs	**(2,181)**	**(985)**	**(3,166)**	(2,324)	(665)	(2,989)
Total operating netback	**17,630**	**4,767**	**21,429**	23,169	3,227	28,135

(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 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) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

($/boe)	Three months ended June 30, 2019 West Central	Eastern	Total	Three months ended June 30, 2018 West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**7,432**	**1,938**	**9,370**	8,758	1,862	10,620
Total petroleum and natural gas revenue	**17.21**	**43.07**	**22.56**	18.59	35.16	21.50
Realized gains (losses) on derivatives	**–**	**–**	**(1.30)**	–	–	1.08
Royalties	**(2.10)**	**(5.90)**	**(2.89)**	(2.51)	(3.49)	(2.68)
Production and operating expenses	**(2.96)**	**(16.49)**	**(5.76)**	(2.25)	(14.82)	(4.45)
Transportation costs	**(1.62)**	**(3.05)**	**(1.92)**	(1.50)	(2.07)	(1.60)
Total operating netback	**10.53**	**17.63**	**10.69**	12.33	14.78	13.85

($/boe)	Six months ended June 30, 2019 West Central	Eastern	Total	Six months ended June 30, 2018 West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**7,984**	**1,819**	**9,803**	9,917	1,758	11,675
Total petroleum and natural gas revenue	**19.26**	**41.32**	**23.35**	18.89	32.06	20.88
Realized gains (losses) on derivatives	**–**	**–**	**(0.54)**	–	–	0.82
Royalties	**(2.79)**	**(4.91)**	**(3.18)**	(2.55)	(3.38)	(2.68)
Production and operating expenses	**(2.77)**	**(18.94)**	**(5.77)**	(2.14)	(16.46)	(4.29)
Transportation costs	**(1.51)**	**(2.99)**	**(1.78)**	(1.29)	(2.09)	(1.41)
Total operating netback	**12.19**	**14.48**	**12.08**	12.91	10.13	13.32

Perpetual's operating netback of $9.1 million ($10.69/boe) in the second quarter of 2019 decreased 32% from $13.4 million ($13.85/boe) in the comparative period of 2018. This decrease was due to 12% lower production caused by natural declines at the East Edson property in West Central, combined with a 6% decrease in realized revenue per boe, due to lower realized pricing across all products. The higher percentage of oil and NGL in the production mix was less impactful during the second quarter of 2019, as realized oil prices were 6% lower than the prior year period due to realized hedging losses on crude oil derivatives of $1.2 million ($11.30/boe).

For the second quarter of 2019, royalties, production and operating expense, and transportation costs per boe were higher than the comparative period of 2018 due to the impact of declining West Central production and growing, higher cost Eastern Alberta heavy oil production.

Perpetual's operating netback of $21.4 million ($12.08/boe) for the six months ended June 30, 2019 decreased 24% from $28.1 million ($13.32/boe) in the comparative period of 2018. The decrease was due to the 16% decrease in total Company production and increased, higher cost Eastern Alberta heavy oil production compared to the same period in 2018.

Production

	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Natural gas *(MMcf/d)*				
Eastern Alberta	**4.5**	5.6	**4.0**	5.2
West Central	**40.0**	47.5	**43.2**	54.2
Total natural gas[(1)]	**44.5**	53.1	**47.2**	59.4
Crude oil *(bbl/d)*				
Eastern Alberta[(2)]	**1,194**	943	**1,154**	901
West Central	**13**	28	**10**	35
Total crude oil	**1,207**	971	**1,164**	936
Total NGL *(bbl/d)*[(3)]	**754**	806	**770**	827
Total production *(boe/d)*	**9,370**	10,620	**9,803**	11,675

(1) Natural gas production yields a heat content of 1.17 GJ/Mcf (2018 – 1.17), resulting in higher realized natural gas prices per Mcf. See "Commodity Prices".
(2) Primarily Mannville heavy oil.
(3) Primarily West Central liquids-rich gas.

Second quarter production averaged 9,370 boe/d, down 12% from 10,620 boe/d in the comparative period of 2018 and was 8% lower than the first quarter of 2019. Perpetual voluntarily shut-in an average 175 boe/d of East Edson production (2% of total production) during the quarter to take advantage of short-term situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.03/Mcf while retaining reserves for future production.

Second quarter natural gas production averaged 40.0 MMcf/d at West Central, down 16% from 47.5 MMcf/d in the comparative period of 2018. Natural gas production has been impacted by limited capital investment in West Central throughout 2018 and 2019, specifically during the summer months when capital investment has been deferred in response to low AECO natural gas prices.

NGL yields at East Edson were 18.9 bbls per MMcf in the second quarter of 2019, up 11% from the comparative period of 2018, and 12% higher than the first quarter of 2019, reflecting the installation of field compression and a sweetening tower in the first quarter of 2019 to restore several higher liquids ratio wells back to production. Perpetual's average NGL sales composition for the second quarter of 2019 consisted of 66% condensate, comparable to the prior year period.

Crude oil production in Eastern Alberta was 27% higher than the second quarter of 2018, reflecting increased production from the 2018 drilling program and lower base declines at Mannville due to waterflood operations. Compared to the first quarter of 2019, Eastern Alberta crude oil production was 7% higher, reflecting decreased maintenance and downtime from winter freeze-ups, combined with the impact of larger downhole pumps installed late in the first quarter. Crude oil production in Eastern Alberta is expected to increase in the second half of 2019 as new production from the 2019 heavy oil drilling program comes on-stream.

For the six months ended June 30, 2019, production decreased 16% to 9,803 boe/d compared to 11,675 boe/d in the prior year period. Production levels decreased through 2018 with reduced capital spending in response to continued volatility in Alberta natural gas prices.

Production at East Edson is expected to decline throughout 2019, prior to new wells from the planned fourth quarter drilling program coming on-stream late in the year.

Commodity Prices

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
Reference prices				
NYMEX Daily Index *(US$/MMBtu)*	**2.64**	2.80	**2.89**	2.90
AECO Daily Index *($/GJ)*	**0.98**	1.12	**1.73**	1.54
AECO Daily Index *($/Mcf)*(1)	**1.03**	1.18	**1.83**	1.63
Alberta Gas Reference Price *($/GJ)*(2)	**0.89**	0.93	**1.39**	1.31
West Texas Intermediate ("WTI") light oil *(US$/bbl)*	**59.81**	67.88	**57.36**	65.37
Western Canadian Select ("WCS") differential *(US$/bbl)*	**(10.68)**	(19.27)	**(11.48)**	(21.77)
WCS average *(Cdn$/bbl)*(3)	**65.83**	62.70	**61.02**	55.81
Average Perpetual prices				
Natural gas *($/Mcf)*(1)				
AECO Daily Index	**1.03**	1.18	**1.83**	1.63
Heat content premium(4)	**0.11**	0.13	**0.20**	0.18
Market diversification contract	**0.84**	1.06	**0.80**	0.69
Realized gains (losses) on financial and physical gas derivatives	**0.28**	0.25	**0.11**	0.04
Realized gains (losses) on prompt month price optimization	**(0.01)**	–	**(0.01)**	0.10
Realized natural gas price *($/Mcf)*(5)	**2.25**	2.62	**2.93**	2.64
Premium to AECO Daily Index	**218%**	222%	**160%**	162%
Premium to AECO Daily Index due to higher heat content	**11%**	11%	**11%**	11%
Realized oil price *($/bbl)*(5)	**50.01**	53.26	**45.76**	50.89
Realized NGL price *($/bbl)*	**51.34**	60.77	**41.61**	59.16

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.

(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.

(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.34 for the three months ended June 30, 2019 (Q2 2018 – $1.29) and $1.33 for the six months ended June 30, 2019 (2018 – $1.28).

(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.17 GJ/Mcf. For the three and six months ended June 30, 2019, Perpetual received an 11% premium to the AECO Daily Index (three and six months ended June 30, 2018 – 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.

NYMEX prices weakened significantly in the second quarter of 2019 compared to first quarter price levels as cooler than normal spring weather reduced air conditioning power generation demand, combined with delays in liquefied natural gas ("LNG") and Mexican export growth. For the six months ended June 30, 2019, United States production was 7.9 Bcf/d higher than the comparative period of 2018. Despite the increase in US production, increases in demand from higher LNG and Mexican exports caused NYMEX natural gas prices to remain essentially flat at US$2.89/MMBtu for the six months ended June 30, 2019 compared to the prior year period (2018 – US$2.90/MMBtu).

AECO pricing also weakened significantly in the second quarter of 2019 compared to first quarter price levels as pipeline system maintenance activities reduced capacity. For the six months ended June 30, 2019, the average AECO Daily Index price increased 12% to $1.73/GJ, compared to $1.54/GJ in the prior year period. The increase in AECO pricing was the result of record-breaking cold weather in Western Canada during February and March that caused significant production freeze-offs in the basin, as well as increased intraprovincial demand requiring large withdrawals from storage to balance the system.

The decrease in WTI to US$57.36/bbl for the six months ended June 30, 2019 from US$65.37/bbl in the comparative period of 2018 was related to concerns over trade issues between the United States and China that threatened the overall health of the global economy, in addition to increasing US crude inventories during the first half of 2019 resulting from the continued growth in production out of the Permian basin. The WCS differential tightened from an average US$21.77/bbl in the first six months of 2018 to US$11.48/bbl in the same period of 2019, due to Alberta Government apportionments to manage the Western Canadian oversupply situation relative to export capacity, effective January 1, 2019.

Perpetual's realized natural gas price, including derivatives, decreased 14% to $2.25/Mcf for the second quarter of 2019 from $2.62/Mcf in the comparative period of 2018, and represented a 218% premium over the AECO Daily Index price, comparable to 222% in the prior year period. During the second quarter of 2019, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, consistent with the comparative period of 2018. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas. The market diversification contract added $0.84/Mcf (Q2 2018 – $1.06/Mcf) on the relative strength of daily index prices at the five downstream markets compared to the AECO Daily Index. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, and increased to 40,000 MMBtu/d on April 1, 2018, expiring October 31, 2022. Pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices. Subsequent to the second quarter, Perpetual extended the term of its market diversification contract by two years. From November 1, 2022 to October 31, 2024, Perpetual will sell 40,000 MMBtu/d at AECO and receive Dawn, Emerson, and Malin daily index prices less US$0.0775/MMBtu and transportation costs from AECO to the market price point. Realized gains on financial and physical gas derivatives, combined with prompt month price optimization operations increased the realized price in the second quarter of 2019 by $0.27/Mcf (Q2 2018 – $0.25/Mcf).

Perpetual's realized oil price of $50.01/bbl was 6% lower than the second quarter of 2018, and included realized hedging losses on crude oil derivative contracts of $1.2 million ($11.30/bbl) on 1,207 bbl/d of production, as the Government of Alberta's mandated production apportionments drastically reduced the WCS differential to WTI prices relative to the Company's oil price risk management positions. Realized prices in the second quarter of 2018 were impacted by realized hedging losses of $4.04/bbl.

Perpetual's realized NGL price for the second quarter of 2019 was $51.34/bbl, down 16% from the second quarter of 2018, reflecting a decrease in all NGL component prices which moved lower in concert with lower WTI light oil prices. Prices for propane, butane and ethane remain disconnected from WTI light oil prices, reflecting excess supply produced from Western Canada and the United States.

Revenue

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Petroleum and natural gas ("P&NG") revenue				
Natural gas[1]	**8,968**	11,254	**23,856**	26,705
Oil	**6,733**	5,063	**11,771**	8,553
NGL	**3,534**	4,457	**5,807**	8,856
Total petroleum and natural gas revenue	**19,235**	20,774	**41,434**	44,114
Realized gains (losses) on derivatives[2]	**(1,110)**	1,048	**(968)**	1,739
Realized revenue	**18,125**	21,822	**40,466**	45,853
Unrealized gains (losses) on derivatives	**(1,791)**	(2,778)	**(9,342)**	(5,104)
Total revenue	**16,334**	19,044	**31,124**	40,749
Realized revenue *($/boe)*	**21.26**	22.58	**22.81**	21.70
Total revenue *($/boe)*	**19.16**	19.71	**17.54**	19.28

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended June 30, 2019 of $19.2 million decreased 7% from the second quarter of 2018, due to the 12% decrease in average daily production combined with the impact of lower realized prices for all products. This was partially offset by the higher proportion of oil and NGL in the production mix. For the six month period ended June 30, 2019, P&NG revenue decreased 6% compared to the prior year period, following the 16% decrease in average daily production, and offset partially by the 11% increase in realized natural gas prices over the same period.

Natural gas revenue, before derivatives, of $9.0 million in the second quarter of 2019 comprised 47% (Q2 2018 – 54%) of total P&NG revenue while natural gas production was 79% (Q2 2018 – 83%) of total production. Natural gas revenue decreased 20% from $11.3 million in the second quarter of 2018, reflecting the impact of the 16% decrease in natural gas production volumes driven by natural declines following deferred capital investment in East Edson during 2018 and the first half of 2019. Perpetual's market diversification contract contributed $3.4 million of incremental revenue ($0.84/Mcf) over the AECO Daily Index price in the quarter (Q2 2018 - $5.1 million and $1.06/Mcf). For the six month period ended June 30, 2019, natural gas revenue decreased 11% compared to the prior year period, primarily due to the 21% decrease in natural gas production, partially offset by the 12% increase in AECO Daily Index prices over the same period.

Oil revenue of $6.7 million represented 35% (Q2 2018 – 24%) of total P&NG revenue while oil production was 13% (Q2 2018 – 9%) of total production. Oil revenue was 33% higher than the same period in 2018, due to the 24% increase in crude oil production combined with the 5% increase in the WCS average price to $65.83/bbl. The 5% increase in the WCS average price was mainly due to the tightening of the WCS differential by US$8.59/bbl to US$10.68/bbl in response to the Government of Alberta's introduction of production quotas effective January 1, 2019. Perpetual did not fully participate in the improved WCS differential, as hedges were in place protecting a WCS differential of US$25.22/bbl on 750 bbl/d for 2019. For the six months ended June 30, 2019, oil revenue increased 38% compared to the prior year period, due primarily to the 24% increase in oil production and the impact of a significantly tighter WCS differential.

NGL revenue for the second quarter of 2019 was $3.5 million, representing 18% (Q2 2018 – 22%) of total P&NG revenue while NGL production was just 8% (Q2 2018 – 8%) of total Company production. NGL revenue decreased by 21% from the prior year period while NGL production decreased only 6%, reflecting the 16% decrease in Perpetual's realized NGL price compared to the prior year period. Compared to the first quarter of 2019, realized NGL prices increased 60% as prices for condensate recovered in the second quarter, close to parity with Cdn$ WTI prices. Condensate production comprised 66% of NGL production in the second quarter (Q1 2019 – 58%). Propane, butane and ethane prices remain disconnected from WTI light oil prices, reflecting excess supply produced from Western Canada and the United States. This oversupply condition is expected to continue. For the six month period ended June 30, 2019, NGL revenue decreased 34% compared to the prior year period, due to the 7% decrease in NGL production combined with a 30% decrease in realized NGL prices.

Realized losses on derivatives totaled $1.1 million for the second quarter of 2019, compared to gains of $1.0 million for the same period of 2018. The realized loss in the current period was comprised of $1.2 million of losses from oil derivatives (Q2 2018 – $0.4 million loss), partially offset by a $0.1 million gain on natural gas derivatives (Q2 2018 – $1.4 million gain).

For the second quarter of 2019, Perpetual recorded an unrealized loss on derivatives of $1.8 million (Q2 2018 - $2.8 million unrealized loss). The unrealized loss relates to the impact of weaker future NYMEX natural gas prices relative to future AECO prices on the Company's basis differential hedge positions. 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 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 June 30, 2019	2018	Six months ended June 30, 2019	2018
Crown	**425**	627	**938**	1,428
Freehold and overriding[1]	**2,039**	1,963	**4,702**	4,225
Total	**2,464**	2,590	**5,640**	5,653
Crown *(% of P&NG revenue)*	**2.2**	3.0	**2.3**	3.2
Freehold and overriding *(% of P&NG revenue)*	**10.6**	9.4	**11.3**	9.6
Total *(% of P&NG revenue)*	**12.8**	12.4	**13.6**	12.8
$/boe	**2.89**	2.68	**3.18**	2.68

(1) Includes $1.1 million in gross overriding royalty payments at East Edson for the three months ended June 30, 2019 (Q2 2018 – $1.2 million) and $2.9 million for the six months ended June 30, 2019 (2018 – $2.8 million).

Royalty expenses for the second quarter of 2019 were $2.5 million, 5% lower than the comparative period of 2018 due to both lower production and P&NG revenue. The combined average royalty rate on P&NG revenue increased from 12.4% in the second quarter of 2018 to 12.8% in 2019. For the six months ended June 30, 2019, royalties were $5.6 million, unchanged from the prior year period despite the 16% decrease in production, due to the impact of higher Alberta Gas Reference prices and AECO Daily Index prices used to calculate crown and freehold natural gas royalties, respectively.

For the three months ended June 30, 2019, crown royalties decreased 32% compared to the prior year period. This decrease reflects the impact of lower production (12% decrease), lower Alberta Gas Reference Prices (4% decrease), and lower WTI light oil prices (12% decrease) compared to the prior year period.

Freehold and overriding royalties have increased 4% from the prior year period, due to the increase in associated liquids at East Edson related to operational changes, which outweighed the decrease in the AECO Daily Index price (13% decrease). At the East Edson property in West Central Alberta, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production. As West Central natural gas production has decreased by 16% for the three months ended June 30, 2019 compared to the prior year period, the fixed nature of the gross overriding royalty has resulted in an increased expense on a percentage of revenue and unit-of-production basis.

Production and operating expenses

($ thousands, except as noted)	Three months ended June 30, 2019	2018[1]	Six months ended June 30, 2019	2018[1]
Production and operating expenses	**4,911**	4,304	**10,231**	9,076
$/boe	**5.76**	4.45	**5.77**	4.29

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

On an absolute dollar basis, production and operating costs were up by $0.6 million, despite the 12% decrease in production, as higher cost Eastern Alberta heavy oil production increased by 27% over the prior year period, comprising 13% of total production in the second quarter (Q2 2018 – 9% of total production). West Central production and operating expenses were essentially flat relative to the first quarter of 2019 at $2.0 million, illustrating the largely fixed cost nature of the East Edson property. For the six months ended June 30, 2019, production and operating expenses were $10.2 million, 13% higher than the prior year period due to the increased proportion of crude oil in the production mix, which is higher cost compared to natural gas production.

Total production and operating expenses were up 29% on a unit-of-production basis to $5.76/boe for the second quarter of 2019, compared to $4.45/boe for the comparable period of 2018. On a cost per boe basis, West Central operating costs increased by 32% to $2.96/boe in the second quarter of 2019 (Q2 2018 – $2.25/boe) due to the impact of declining natural gas production against a relatively fixed cost base. Eastern Alberta operating costs increased 11% to $16.49/boe over the same period (Q2 2018 – $14.82/boe) but declined from $21.76/boe in the first quarter of 2019, reflecting decreased well servicing and pump replacement costs.

Compared to the first quarter of 2019, production and operating expenses of $4.9 million were 8% lower (Q1 2019 – $5.3 million), as winter maintenance and pump change costs in Eastern Alberta did not re-occur in the second quarter.

Transportation costs

($ thousands, except as noted)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Transportation costs	**1,635**	1,546	**3,166**	2,989
$/boe	**1.92**	1.60	**1.78**	1.41

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. Transportation costs in the second quarter of 2019 were $1.6 million, slightly higher than the prior year period of $1.5 million due to higher oil and NGL production which results in higher per unit trucking costs. Transportation costs averaged $1.62/boe at West Central compared to $3.05/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.92/boe in the second quarter, up 20% from the prior year period due to the impact of fixed firm-capacity natural gas transportation costs against lower production and increased higher cost trucking volumes in Eastern Alberta. For the six months ended June 30, 2019, transportation costs were $3.2 million, 6% higher than the prior year period for the same reasons noted above.

Gas over bitumen

($ thousands, except as noted)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Gas over bitumen royalty credit	**146**	170	**534**	553
Payments on gas over bitumen royalty financing[1]	**(290)**	(260)	**(685)**	(699)
Gas over bitumen, net of payments	**(144)**	(90)	**(151)**	(146)
$/boe	**(0.17)**	(0.09)	**(0.09)**	(0.07)

(1) At June 30, 2019, the fair value of the gas over bitumen royalty financing was estimated to be $0.8 million (December 31, 2018 – $1.1 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation for natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During the second quarter of 2019, Perpetual recorded $0.1 million in gas over bitumen revenue, 14% lower than the same period of 2018. Gas over bitumen revenue was impacted by the 4% decrease in the Alberta Gas Reference Price, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the second quarter of 2019 funded payments of $0.3 million (Q2 2018 – $0.3 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. As part of the arrangement, Perpetual makes monthly payments to the purchaser, which from time to time will vary from the actual gas over bitumen royalty credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen royalty credit, with final expiries expected to occur in June 2021.

Under IFRS, the monetization of future gas over bitumen royalty credits is recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenues from gas over bitumen royalty adjustments are not recorded as an asset, but as revenue with the passage of time as it is earned. As such, gas over bitumen revenue will continue to be recognized separately as revenue in accordance with Perpetual's accounting policies, with the monthly payments recognized as a reduction to the gas over bitumen royalty financing obligation. For purposes of this MD&A, the monthly payments have been included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty adjustments. During the second quarter of 2019, the gas over bitumen royalty financing obligation decreased by $0.3 million, comprised of payments of $0.3 million.

During the six months ended June 30, 2019, the gas over bitumen royalty financing obligation decreased by $0.3 million, comprised of payments of $0.7 million, partially offset by an unrealized loss of $0.4 million. The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation during the first quarter of 2019.

Exploration and evaluation ("E&E") expenses

($ thousands)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Lease rentals[1]	**(113)**	172	**51**	342
Geological and geophysical costs	**8**	–	**8**	–
Lease expiries (non-cash)	**61**	–	**61**	–
Total E&E expense	**(44)**	172	**120**	342

(1) Commencing in the second quarter of 2019, developed mineral lease rentals have been classified as production and operating expenses.

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 second quarter of 2019, the Company recorded $0.1 million of non-cash write-downs 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 June 30, 2019	2018[1]	Six months ended June 30, 2019	2018[1]
Cash G&A expense	**3,563**	3,475	**7,250**	7,389
Overhead recoveries	**(386)**	(345)	**(602)**	(948)
Total G&A expense	**3,177**	3,130	**6,648**	6,441
$/boe	**3.73**	3.24	**3.75**	3.05

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

During the second quarter of 2019, cash G&A expense was $3.6 million, comparable with the prior year period of $3.5 million. Compared to the first quarter of 2019, overhead recoveries increased by 79% due to increased capital expenditures from accelerating the Mannville heavy oil drilling program into the second quarter to take advantage of dry surface lease conditions. On a unit-of-production basis, total G&A expense of $3.73/boe for the second quarter of 2019 was up 15% from the prior year period, due to the impact of decreasing production. For the six months ended June 30, 2019, cash G&A expense was $7.3 million, slightly lower than the prior year period of $7.4 million.

Share-based payments

($ thousands, except as noted)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Share-based payments expense (non-cash)	**616**	693	**1,324**	1,499
$/boe	**0.72**	0.72	**0.75**	0.71

Non-cash share-based payments expense for the three months ended June 30, 2019 was $0.6 million, down 11% compared to the same period in 2018 due to a reduction in the value of outstanding share-based payment awards. No new awards were granted in the second quarter of 2019. For the six months ended June 30, 2019, share-based payments expense was $1.3 million, 12% lower than the prior year period for the same reasons noted above.

Depletion and depreciation

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2019**	2018[(1)]	**2019**	2018[(1)]
Depletion and depreciation	**8,171**	8,783	**16,730**	18,907
$/boe	**9.58**	9.09	**9.43**	8.95

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Perpetual recorded $8.2 million of depletion and depreciation expense for the three months ended June 30, 2019, a decrease of 7% from $8.8 million recorded in the prior year period. The decrease reflects the 12% decline in production volumes compared to the prior year period.

Impairment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. For the quarter ended June 30, 2019, the Company assessed impairment indicators for the Company's cash-generating units ("CGU"). In performing the review, management determined that the decrease in reserve values linked to declining natural gas prices justified calculation of the recoverable amount of the West Central CGU. The recoverable amount of the West Central CGU was determined using value-in-use ("VIU") based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators, along with commodity price estimates based on an average of three independent reserve evaluators, and an estimate of market discount rates between 10% and 20% to consider risks specific to the asset. At June 30, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount and accordingly, an impairment charge of $22.6 million was included in net loss.

Finance expenses

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2019**	2018	**2019**	2018
Cash finance expense				
Interest on revolving bank debt	**657**	504	**1,340**	972
Interest on TOU share margin demand loan	**115**	162	**236**	310
Interest on term loan	**887**	907	**1,798**	1,818
Interest on senior notes	**741**	722	**1,452**	1,443
Interest on lease liabilities[(1)]	**48**	–	**98**	–
Dividend income from TOU share investment	**(198)**	(152)	**(364)**	(285)
Total cash finance expense	**2,250**	2,143	**4,560**	4,258
Non-cash finance expense				
Amortization of debt issue costs	**266**	267	**538**	517
Accretion on decommissioning obligations	**196**	208	**411**	415
Change in fair value of gas over bitumen royalty financing	**(47)**	198	**361**	68
Total non-cash finance expense	**415**	673	**1,310**	1,000
Finance expenses recognized in net loss	**2,665**	2,816	**5,870**	5,258

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Total cash finance expense of $2.3 million for the three months ended June 30, 2019 was 5% higher than the prior year period (Q2 2018 – $2.1 million), due to increased interest expense on the reserve-based revolving credit facility (the "Credit Facility") associated with higher floating interest rates, partially offset by dividend income of $0.2 million ($0.12 per TOU share) received from the TOU share investment during the second quarter of 2019 (Q2 2018 – $0.2 million and $0.09 per TOU share). For the six months ended June 30, 2019, total cash finance expense was $4.6 million, 7% higher than the prior year period, also due to higher interest rates on the Credit Facility.

Total non-cash finance expense for the three months ended June 30, 2019 was $0.4 million (Q2 2018 – $0.7 million). A decrease in the fair value of the gas over bitumen royalty financing was recorded in the second quarter of 2019 due to lower AECO future natural gas prices, resulting in a fair value at June 30, 2019 of $0.8 million.

Change in fair value of TOU share investment

During the three months ended June 30, 2019, Perpetual recorded an unrealized loss of $6.6 million related to the change in fair value of the TOU share investment, which represents the 19% decrease in value of TOU shares held from March 31, 2019 ($20.64 per share) to June 30, 2019 ($16.68 per share). At June 30, 2019, the Company owned 1.66 million TOU shares (December 31, 2018 – 1.66 million shares) having a fair market value of $27.6 million (December 31, 2018 – $28.1 million).

LIQUIDITY AND CAPITAL RESOURCES

Perpetual's strategy includes maintaining 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, declines in the fair value of the Company's investment in TOU shares, 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, TOU share margin demand loan, and net working capital, with value and liquidity enhanced through the ownership of TOU shares. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell its TOU shares or other 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.

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an over two-year-old transaction when, on October 1, 2016, Perpetual closed the Shallow Gas Disposition to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them. Perpetual's Application for Summary Dismissal was heard during the fourth quarter of 2018. The Court's decision is scheduled to be received on August 15, 2019. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

On July 18, 2019, Moody's Investors Service updated Perpetual's credit rating. The Company's corporate and senior note credit ratings were confirmed at Caa2 and Caa3 respectively, with the outlook improved from "negative" to "stable" based on an improved near-term liquidity assessment due to the extension of the Credit Facility term to November 2020 and the repayment of the 2019 Senior Notes and issuance of new 2022 Senior Notes.

Capital management

($ thousands, except as noted)	**June 30, 2019**	December 31, 2018[(4)]
Revolving bank debt	**37,806**	42,561
Term loan, principal amount	**45,000**	45,000
TOU share margin demand loan, principal amount	**13,515**	14,144
Senior notes, principal amount	**33,580**	32,490
TOU share investment[(1)]	**(27,635)**	(28,132)
Net working capital deficiency[(2)]	**10,251**	6,543
Net debt[(2)]	**112,517**	112,606
Shares outstanding at end of period *(thousands)*[(3)]	**60,337**	60,240
Market price at end of period *($/share)*	**0.21**	0.20
Market value of shares	**12,671**	12,048
Enterprise value[(2)]	**125,188**	124,654
Net debt as a percentage of enterprise value *(%)*	**90**	90
Trailing twelve-months adjusted funds flow[(2)(4)]	**23,218**	30,155
Net debt to trailing twelve-months adjusted funds flow *(times)*	**4.8**	3.7

(1) The TOU share investment is based on the June 30, 2019 closing price per the Toronto Stock Exchange ($16.68 per share) and 1.66 million TOU shares held (December 31, 2018 – 1.66 million TOU shares held with a closing price of $16.98 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

At June 30, 2019, Perpetual had total net debt of $112.5 million, unchanged from December 31, 2018 and $10.2 million higher than March 31, 2019. The increase in net debt from the first quarter of 2019 was mainly attributable to the $6.6 million decrease in the fair value of TOU shares during the second quarter of 2019, combined with capital expenditures which exceeded net cash flow from operations during the period. The net working capital deficiency increased by $4.9 million from March 31, 2019, due to increased capital expenditures during the second quarter of 2019, resulting in higher accounts payable and accrued liability balances at June 30, 2019 compared to March 31, 2019.

As at June 30, 2019, 70% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve-months adjusted funds flow at the end of the second quarter increased to 4.8 times (December 31, 2018 – 3.7 times; March 31, 2019 – 3.7 times), due primarily to the impact of lower adjusted funds flow.

Perpetual had available liquidity at June 30, 2019 of $27.6 million, comprised of an unutilized revolving bank debt Borrowing Limit of $13.5 million and the market value of its TOU share investment, net of the principal amount of the associated TOU share margin demand loan, of $14.1 million.

TOU share margin demand loan

At June 30, 2019, Perpetual had a $13.5 million TOU share margin demand loan secured by 1.66 million TOU shares (December 31, 2018 - $14.1 million). Interest rates are based on 90-day Banker's Acceptance rates plus 1.25%. Perpetual may repay a portion or the entirety of the loan at any time. Any repayment is a permanent reduction to the loan. Perpetual is required to maintain a lending ratio of less than 55% based on the ratio of the TOU share margin demand loan compared to the market value of the pledged TOU shares (the "Lending Ratio"). If at any time the Lending Ratio exceeds 55%, Perpetual is obligated to pay down the TOU share margin demand loan to restore the Lending Ratio to 40%. As at June 30, 2019, the Lending Ratio was 49% of the closing market value of the pledged TOU shares.

During the three months ended June 30, 2019, the TOU share price declined in value, prompting the Company to voluntarily pay down the TOU share margin demand loan by $0.5 million to maintain the Lending Ratio at less than 55%, funded from borrowings on its Credit Facility.

The effective interest rate on the TOU share margin demand loan as at June 30, 2019 was 3.3% (June 30, 2018 – 4.1%). If interest rates changed by 1%, with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.1 million (June 30, 2018 – $0.2 million).

In addition to the Lending Ratio requirements, the TOU share margin demand loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin demand loan covenants as at June 30, 2019.

Revolving bank debt

As at June 30, 2019, the Company's Credit Facility had a Borrowing Limit of $55.0 million (December 31, 2018 – $55.0 million) under which $37.8 million was drawn (December 31, 2018 – $42.6 million) and $3.7 million of letters of credit had been issued (December 31, 2018 – $3.7 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 2.0% and 4.5%.

On March 27, 2019, the $55 million Borrowing Limit was confirmed by the Company's lenders and the maturity was extended from May 31, 2019 to November 30, 2020. The Credit Facility will revolve until May 31, 2020 and may be extended for a further 364-day period subject to approval by the Company's lenders. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on November 30, 2020. The next Borrowing Limit redetermination is scheduled on or prior to November 30, 2019.

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 the TOU shares that have been pledged as security for the TOU share margin demand loan and 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 second lien and unsecured debt and to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at June 30, 2019 was 6.0% (June 30, 2018 – 4.6%). If interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.4 million (June 30, 2018 – $0.4 million).

At June 30, 2019, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

			June 30, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	March 14, 2021	8.1%	**$ 45,000**	**$ 43,995**	$ 45,000	$ 43,729

The term loan bears a fixed interest rate of 8.1% with semi-annual interest payments due June 30 and December 31 of each year. 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 has a cross-default provision with the Credit Facility and contains substantially similar 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, TOU shares secured in favor of the TOU share margin demand loan lenders, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At June 30, 2019, the term loan is presented net of $1.0 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.5%.

At June 30, 2019, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			June 30, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**$ –**	**$ –**	$ 14,572	$ 14,536
2022 Senior Notes	January 23, 2022	8.75%	**33,580**	**31,975**	17,918	17,344
			$ 33,580	**$ 31,975**	$ 32,490	$ 31,880

On May 7, 2019, Perpetual announced the early redemption of all of the $14.6 million aggregate principal amount of 2019 Senior Notes effective June 11, 2019 (the "Redemption Date").

Pursuant to the early redemption, holders of the 2019 Senior Notes would receive CDN $1,000 for each $1,000 principal amount of 2019 Senior Notes (the "Cash Consideration"); or, at the election of the holder, $1,075 principal amount of 2022 Senior Notes for each $1,000 principal amount of 2019 Senior Notes (the "2022 Senior Notes Consideration") plus cash in the amount of $33.32 per $1,000 principal amount of 2019 Senior Notes, representing all accrued and unpaid interest at the Redemption Date.

The Company's President and Chief Executive Officer (the "Backstopper") unconditionally committed to fully fund all of the Cash Consideration by advancing all, or a portion of any, of the Cash Consideration as determined by the Corporation to holders electing to receive the Cash Consideration in consideration for the deemed transfer by such holders to the Backstopper of an aggregate principal amount of 2019 Senior Notes that is equal to the aggregate Cash Consideration advanced by the Backstopper. Furthermore, the Backstopper irrevocably elected to receive the 2022 Senior Notes Consideration in exchange for the 2019 Senior Notes obtained by funding any Cash Consideration.

On June 11, 2019, the Company completed the early redemption of the $14.6 million 2019 Senior Notes. Pursuant to the early redemption, the Company issued $15.7 million 2022 Senior Notes to fully redeem the 2019 Senior Notes, of which $15.6 million were issued to the Backstopper in consideration for funding the Cash Consideration as requested by Perpetual. After giving effect to this senior note refinancing, there are $33.6 million 2022 Senior Notes outstanding comprised of $17.9 million 2022 Senior Notes previously outstanding, and the $15.7 million 2022 Senior Notes issued as consideration to redeem the 2019 Senior Notes. Entities controlled or directed by the Company's President and Chief Executive Officer hold $22.5 million of the 2022 Senior Notes now outstanding.

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 31 and July 31 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. Within three years of maturity, the Company may redeem up to 100% of the senior notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100% of the senior notes at the principal amount.

At June 30, 2019, the 2022 Senior Notes are recorded at the present value of future cash flows, net of issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 10.9%.

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. The permitted amount of any restricted payment is limited to:

i) To the extent the Company's Consolidated Debt (defined as the sum of the period end balance of revolving bank debt, the term loan, TOU share margin demand loan and gas over bitumen royalty financing) to trailing twelve-months income before interest, taxes, depletion and depreciation and non-cash items ("TTM EBITDA") is less than 3.0 to 1.0 (the "Consolidated Debt Ratio"), the sum of 50% of TTM EBITDA from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100% of the fair market value of any equity contributions made to the Company during that period less the sum of all restricted payments during that period; and

ii) To the extent the Company's Consolidated Debt Ratio is greater than or equal to 3.0 to 1.0 pro forma for the proposed restricted payment, $50 million plus 100% of the fair market value of any equity contributions made to the Company.

At June 30, 2019, other than the restricted payment covenants noted above, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Equity

At June 30, 2019 there were 60.3 million common shares outstanding, net of 0.8 million shares held in trust to resource employee compensation programs. During the six months ended June 30, 2019, 0.5 million shares were purchased by the independent trustee to be held in trust, for a total cost to the Company of $0.2 million. Basic and diluted weighted average shares outstanding for the three months ended June 30, 2019 were 60.2 million (Q2 2018 – 59.9 million) and 60.1 million for the six months ended June 30, 2019 (2018 – 59.6 million).

At July 31, 2019 there were 60.2 million common shares outstanding which is net of 0.9 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)	**July 31, 2019**
Share options	**4.7**
Performance share rights[1]	**1.0**
Compensation awards[1]	**5.6**
Warrants	**6.5**
Total	**17.8**

(1) 1.0 million performance share rights and 1.5 million compensation awards have an exercise price below the June 30, 2019 closing price of the Company's common shares of $0.21 per share.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q2 2019**	Q1 2019	Q4 2018[3]	Q3 2018[3]
Financial				
Oil and natural gas revenue	**19,235**	22,199	21,510	20,504
Net loss	**(36,276)**	(4,892)	(331)	(12,259)
Per share – basic and diluted	**(0.60)**	(0.08)	(0.01)	(0.20)
Cash flow from operating activities	**4,295**	9,292	5,163	6,729
Adjusted funds flow[1]	**3,649**	6,362	8,052	5,155
Per share – basic and diluted	**0.06**	0.11	0.13	0.09
Capital expenditures	**5,200**	1,238	5,617	4,343
Net payments (proceeds) on acquisitions and dispositions	**–**	–	(1,285)	4,341
Net capital expenditures	**5,200**	1,238	4,332	8,684
Common shares *(thousands)*				
Weighted average – basic and diluted	**60,154**	60,111	60,448	60,468
Operating				
Daily average production				
Natural gas *(MMcf/d)*	**44.5**	50.0	44.9	46.9
Oil *(bbl/d)*	**1,207**	1,121	1,301	1,022
NGL *(bbl/d)*	**754**	785	715	730
Total *(boe/d)*	**9,370**	10,240	9,491	9,569
Average prices				
Realized natural gas price *($/Mcf)*[2]	**2.25**	3.54	4.38	2.83
Realized oil price *($/bbl)*[2]	**50.01**	41.12	19.83	48.57
Realized NGL price *($/bbl)*	**51.34**	32.16	35.73	56.02

($ thousands, except as noted)	Q2 2018[3]	Q1 2018[3]	Q4 2017[3]	Q3 2017[3]
Financial				
Oil and natural gas revenues	20,774	23,340	23,810	20,026
Net loss	(1,325)	(6,465)	(6,498)	(8,082)
Per share – basic and diluted	(0.02)	(0.11)	(0.11)	(0.14)
Cash flow from operating activities	8,435	11,198	10,953	5,778
Adjusted funds flow[1]	7,847	9,101	12,541	8,199
Per share – basic and diluted	0.13	0.15	0.21	0.14
Capital expenditures	2,031	14,897	19,047	25,392
Net payments (proceeds) on acquisitions and dispositions	(7,012)	926	970	680
Net capital expenditures	(4,981)	15,823	20,017	26,072
Common shares *(thousands)*				
Weighted average – basic and diluted	59,876	59,345	59,338	59,152
Operating				
Daily average production				
Natural gas *(MMcf/d)*	53.1	65.9	60.8	51.8
Oil *(bbl/d)*	971	900	888	978
NGL *(bbl/d)*	806	848	738	733
Total *(boe/d)*	10,620	12,742	11,765	10,330
Average prices				
Realized natural gas price *($/Mcf)*[2]	2.62	2.65	3.22	3.11
Realized oil price *($/bbl)*[2]	53.26	48.31	47.30	43.01
Realized NGL price *($/bbl)*	60.77	57.61	54.17	39.06

(1) See "Non-GAAP measures" in this MD&A.
(2) Realized natural gas and oil 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.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

The Company's oil and natural gas revenues, net loss, cash flow from operating activities and adjusted funds flow are influenced by commodity prices and production levels. Production levels increased throughout 2017 as net capital expenditures were increased in response to improving commodity prices. Natural gas production levels decreased during 2018 due to reduced capital expenditures in response to depressed AECO natural gas prices, and due to the shut-in of approximately 700 boe/d of production during the second, third and fourth quarters of 2018 at East Edson associated with the Sequoia bankruptcy. This production was restarted in mid-December 2018, causing natural gas production to increase in the first quarter of 2019. Capital expenditures increased in the second quarter of 2019, as planned oil drilling was accelerated from the third quarter to take advantage of dry surface lease conditions. The net loss for the second quarter of 2019 was $36.3 million ($0.60/share), significantly higher than prior quarter levels due to an impairment charge of $22.6 million recognized during the second quarter of 2019, combined with the $6.6 million decrease in the fair value of the TOU share investment. Capital expenditures are typically low during the second quarter when break-up conditions in Alberta reduce access for field activities.

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 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 commodity price risk management contracts outstanding at July 31, 2019:

Natural Gas

The Company has open physical and financial natural gas arrangements in place at AECO as summarized in the table below. Settlements on physical sales contracts are recognized in oil and natural gas revenue.

Term	Volumes sold (bought) at AECO *(GJ/d)*	Average price *($/GJ)*(1)	Market prices *($/GJ)*(2)	Type of contract
July 2019 – October 2019	15,551	1.57	1.09	Physical
July 2019 – October 2019	6,000	1.10	1.09	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for July 2019 are based on settled AECO Monthly Index prices. Market prices for subsequent months are based on forward AECO Monthly Index prices as of market close on July 31, 2019.

The following table provides a summary of physical and financial basis differential contracts between AECO and NYMEX:

Term	Volumes sold (bought) *(MMBtu/d)*	AECO-NYMEX differential *(US$/MMBtu)*(1)	Market prices *(US$/MMBtu)*(2)	Type of contract
July 2019 – December 2019	7,500	(1.50)	(1.21)	Financial
July 2019 – December 2019	2,500	(1.55)	(1.21)	Physical
November 2019 – December 2019	10,000	(1.54)	(0.95)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.20)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.20)	Physical
January 2021 – December 2021	15,000	(1.31)	(1.13)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for July 2019 are based on settled AECO-NYMEX differential prices. Market prices for subsequent months are based on forward AECO-NYMEX differential prices as of market close on July 31, 2019.

Crude Oil

The Company had entered into financial WTI oil sales arrangements in US$ as follows:

Term	Volumes *(bbl/d)*	Floor price *(US$/bbl)*	Ceiling price *(US$/bbl)*	Market prices *(US$/bbl)*(1)	Type of contract
July 2019 – December 2019	500	60.00	72.40	58.16	Financial

(1) Market prices are based on forward WTI oil prices as of market close on July 31, 2019.

Term	Volumes *(bbl/d)*	WTI average price *(US$/bbl)*	Market prices *(US$/bbl)*(2)	Type of contract
August 2019 – December 2019	250	60.00	58.40	Financial

The following table provides a summary of basis differential contracts between WTI and WCS:

Term	Volumes *(bbl/d)*	WTI-WCS differential *(US$/bbl)*(1)	Market prices *(US$/bbl)*(2)	Type of contract
July 2019 – September 2019	250	(17.60)	(12.81)	Financial
July 2019 – December 2019	750	(25.22)	(14.91)	Financial
January 2020 – December 2020	500	(19.75)	(19.75)	Financial

(1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
(2) Market prices for July 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 July 31, 2019.

The following table provides a summary of WCS fixed price contracts:

Term	Volumes *(bbl/d)*	WCS average price *($/bbl)*[(1)]	Market prices *($/bbl)*[(2)]	Type of contract
January 2020 – December 2020	250	50.00	48.65	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward WCS prices as of market close on July 31, 2019.

NGL

The following table provides a summary of financial NGL basis differential arrangements between WTI and Edmonton condensate pricing:

Term	Volumes *(bbl/d)*	WTI Edmonton condensate differential *(US$/bbl)*[(1)]	Market prices *(US$/bbl)*[(2)]	Type of contract
July 2019 – June 2020	350	(6.15)	(4.46)	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward WTI Edmonton condensate differential prices as of market close on July 31, 2019.

Foreign Exchange

The Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated natural gas sales:

Term	Notional *(US$ thousands/month)*	Strike rate *(US$/Cdn$)*[(1)]	Market prices *(US$/Cdn$)*[(2)]
July 2019 – October 2019	2,000	1.31	1.32
November 2019 – March 2020	2,000	1.29	1.32
April 2020 – October 2020	1,500	1.30	1.31

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward US$/Cdn$ exchange rates as of market close on July 31, 2019.

Natural Gas Sales Obligations

Natural gas sales obligations pursuant to the Company's five-year market diversification contract include a fixed volume obligation of 40,000 MMBtu/d until October 31, 2024, delivered to AECO and are priced at daily index prices at each of the five market price points, less transportation costs from AECO to each market price point as detailed below.

Market/Pricing Point	July 1, 2019 to October 31, 2022 Daily sales volume *(MMBtu/d)*	November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)*
Chicago	12,200	–
Malin	10,800	15,000
Dawn	8,000	15,000
Michcon	5,200	–
Empress	3,800	–
Emerson	–	10,000
Total natural gas sales volume obligation	**40,000**	**40,000**

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

ACCOUNTING PRONOUNCEMENTS

Recently adopted

IFRS 16 "Leases"
On January 1, 2019, Perpetual adopted IFRS 16 using the modified retrospective approach. This approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the condensed interim consolidated financial statements has not been restated.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "Leases" ("IAS 17"). Under the principles of the new standard, these leases have been measured at the present value of the remaining lease payments, discounted using Perpetual's estimated incremental borrowing rates at January 1, 2019, adjusted for the term and nature of leased assets. Incremental borrowing rates as at January 1, 2019 ranged from 4.3% to 6.6%. The associated right-of-use ("ROU") assets were measured at an amount equal to the lease liability on January 1, 2019, with no impact on retained earnings.

On adoption, the Corporation elected to use the following practical expedients permitted under the new standard:

- ROU assets and lease liabilities for leases with a remaining term of less than twelve months as at January 1, 2019 were not recognized;
- ROU assets and lease liabilities for leases of low dollar value were not recognized;

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Excluded initial direct costs from measuring ROU assets at the date of initial application; and
- Adjusted the ROU assets by the amount of an IAS 37 lease inducement provision immediately before the date of initial application, as an alternative to an impairment review.

The impact of the adoption of IFRS 16 as at January 1, 2019 is as follows:

- Recorded lease liabilities of $3.1 million; and
- Recorded ROU assets of $1.8 million, equal to the lease liabilities of $3.1 million less $1.3 million previously recognized as a lease inducement under IAS 37. ROU assets are comprised of $1.5 million for the head office lease, $0.2 million for vehicle leases, and $0.1 million for other leases.

The adoption of the new standard had the following impact on the Company's financial results for the six months ended June 30, 2019, compared to what would have occurred had the new accounting policy not been adopted:

(*$ thousands, except as noted*)	**Decrease (increase) in net loss**	**Impact on net cash flows from (used in) operating activities and adjusted funds flow[(1)]**
Production and operating expense	47	47
General and administrative expense	168	168
Depletion and depreciation expense	(192)	–
Cash interest on lease liabilities	(98)	(98)
Net IFRS 16 implementation impact	**(75)**	**117**

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

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 2 to the condensed interim consolidated financial statements.

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.

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 April 1, 2019 and ended June 30, 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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 heading "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 quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas, NGL and 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 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 2019 and 2020; the retention of, and benefits to be received from holding the TOU share investment; 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.

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. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and neither the Corporation nor any of its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.