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 nine months ended September 30, 2018 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 nine months ended September 30, 2018 as well as audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. The MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2017 as disclosure which is unchanged from the December 31, 2017 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"). 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 November 7, 2018.

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", "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, in order 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 the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"), which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' (Q3 2018 – $0.1 million; and Q3 2017 – nil) from the calculation of adjusted funds flow as these costs are no longer significant to the Company's business. The calculation of adjusted funds flow for comparative periods has been adjusted to give effect to this change.

Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating 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 September 30,		Nine months ended September 30,	
($ thousands, except per share and per boe amounts)	**2018**	2017	**2018**	2017
Net cash flows from operating activities	**6,729**	5,778	**26,362**	8,217
Changes in non-cash working capital	**(1,698)**	1,675	**(4,825)**	8,701
Expenditures on decommissioning obligations	**252**	887	**1,158**	1,424
Change in gas over bitumen royalty financing	**(179)**	(558)	**(878)**	(2,084)
Payments of restructuring costs	**51**	417	**286**	2,316
Adjusted funds flow	**5,155**	8,199	**22,103**	18,574
Adjusted funds flow per share	**0.09**	0.14	**0.37**	0.32
Adjusted funds flow per boe	**5.86**	8.63	**7.38**	7.36

Available Liquidity: Available Liquidity is defined as Perpetual's Credit Facility Borrowing Limit, plus Tourmaline Oil Corp. ("TOU") share investment, less borrowings and letters of credit issued under the Credit Facility and TOU share margin demand loan. Management uses available liquidity to assess the ability of the Company to finance capital expenditures, expenditures on decommissioning obligations and meet 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 interest expense and income. Cash costs per boe is calculated by dividing cash costs by total production sold in the period.

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except per boe amounts*)	**2018**	2017	**2018**	2017
Royalties	**2,658**	2,614	**8,311**	9,322
Production and operating	**5,302**	3,326	**14,378**	12,561
Transportation	**1,590**	1,331	**4,579**	3,572
General and administrative	**3,396**	2,850	**9,837**	9,093
Cash interest expense and income	**2,207**	1,998	**6,465**	5,816
Cash costs	**15,153**	12,119	**43,570**	40,364
Cash costs per boe	**17.21**	12.75	**14.56**	16.00

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.

Net debt and net bank debt: 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 mark-to-market value of the TOU share investment. Net bank debt and net debt are used by management to analyze borrowing capacity.

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, revolving bank debt, senior notes, and current portion of provisions.

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, operating costs, and transportation 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.

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized NGL revenue which includes realized gains (losses) on financial natural gas, crude oil and foreign exchange contracts but excludes any realized gains (losses) resulting from contracts related to the disposition of the Shallow Gas Properties. Realized revenue, including foreign exchange contracts, is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements on 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, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

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.

THIRD QUARTER 2018 HIGHLIGHTS

Natural gas prices in Alberta continued to experience weakness during the third quarter of 2018, with average AECO Daily Index prices a further 18% lower than the depressed third quarter prices experienced a year ago. Perpetual's proactive market diversification strategy implemented in 2017 provided a 98% uplift over average AECO Daily Index prices during the third quarter (Q3 2017 – nil).

Exploration and development spending for the third quarter of 2018 was $4.3 million, of which 96% was incurred at Mannville to drill three (3.0 net) new heavy oil horizontal wells and one (1.0 net) re-entry where three horizontal laterals were added to an existing horizontal well. Two of the four wells were tied-in to production at the end of the third quarter, and two came online during the first week of October.

Production averaged 9,569 boe/d in the third quarter of 2018, down 7% from the comparable period in 2017. The decrease was driven by approximately 700 boe/d of production that was shut-in at East Edson throughout the second and third quarters at the request of the Alberta Energy Regulator after the operator of record, Sequoia Resources Corp. ("Sequoia"), filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held by Sequoia following the Shallow Gas Disposition. Production was shut-in, pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. Perpetual anticipates that production from these wells will resume by early 2019. Compared to the second quarter of 2018, production was down 10%. The decrease was driven by natural declines in East Edson resulting from limited capital investment during 2018 in response to low AECO natural gas prices.

Realized revenue was $23.34/boe in the third quarter of 2018 compared to $21.77/boe in the prior year period, up 7% as the impact of the 18% reduction in the AECO Daily Index natural gas price from the comparative period was largely offset by higher sales prices realized through Perpetual's natural gas market diversification contract to markets outside of Alberta, combined with higher oil and natural gas liquids ("NGL") selling prices in the third quarter of 2018. Deliveries to the market diversification contract commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018. The market diversification contract is expected to continue to provide for enhanced risk management through future periods of volatile natural gas prices in Western Canada related to market access constraints.

Cash costs were $17.21/boe in the third quarter of 2018, up 35% compared to the prior year period due to higher operating costs resulting from a produced water spill at the Company's Mannville heavy oil operation. Clean-up costs of approximately $0.8 million were incurred during the quarter, increasing operating costs by $0.91/boe. Additionally, operating costs in the comparative period of 2017 were reduced by a $0.9 million ($0.95/boe) non-recurring adjustment associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. Operating costs at West Central Alberta were $2.44/boe for the three months ended September 30, 2018, down 4% from the prior year period. Total general and administrative expenses increased by 19% over the prior year period, due primarily to Sequoia litigation defence costs, combined with reduced overhead recoveries following the reduction in capital expenditures.

The net loss for the third quarter of 2018 was $12.3 million ($0.20/share), compared to a net loss of $8.1 million ($0.14/share) in the comparative period of 2017. The increase in net loss from the prior year period was due primarily to a $7.2 million ($0.12/share) write-down of E&E assets during the third quarter of 2018.

Cash flow from operating activities in the third quarter of 2018 was $6.7 million ($0.11/share) compared to cash flow from operating activities in the prior year period of $5.8 million ($0.10/share).

Adjusted funds flow in the third quarter of 2018 was $5.2 million ($0.09/share), down 37% from the prior year period of $8.2 million ($0.14/share) due to decreased production and higher cash costs, and despite higher realized revenue per boe. Adjusted funds flow was $5.86/boe in the third quarter of 2018, down 32% from the prior year period of $8.63/boe.

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 almost 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 award 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 and that they constitute an abuse of process. Perpetual's Application for Summary Dismissal is scheduled to be heard on November 8, 2018 with the Court's decision expected by the end of December.

OUTLOOK

2018 capital spending and production guidance

Perpetual anticipates 2018 exploration and development capital expenditures of approximately $25 to $26 million ($4 to $5 million for the fourth quarter), reducing the upper end of its previous guidance of $25 to $30 million provided in its second quarter financial and operating results press release dated August 2, 2018 (the "Q3 Guidance"). The Mannville heavy oil drilling program for the second half of 2018 has been reduced from the Q3 Guidance of 4.3 – 8.3 net wells to 3.0 net wells, plus one re-entry. The expanded drilling program was deferred to allow more time to monitor performance from the first quad lateral re-entry, to remediate the produced water spill at Mannville, and due to the alternative use of funds to acquire a partner's interest in one of the Company's operated Mannville heavy oil pools. Furthermore, the Company expects that heavy oil differentials will narrow in the second half of 2019, improving economics for the heavy oil drills.

At East Edson, one horizontal well drilled in the first quarter of 2018 will be completed and tied-in during the fourth quarter. Additionally, the installation of field compression and a sweetening tower is targeting to restore several higher liquids ratio wells back to production. The timing of the capital activity is designed to align high initial production rates with higher anticipated winter natural gas prices.

Decommissioning expenditures are anticipated to be $0.5 to $1.0 million for the remainder of 2018, consistent with Q3 Guidance. Capital spending during the remainder of 2018 will be funded from adjusted funds flow.

Production for 2018 is expected to be 10,250 boe/d to 10,750 boe/d, down slightly from Q3 Guidance, as the re-start of production from the 700 boe/d four well pad at Edson is not forecast to commence until early 2019, and extremely low AECO gas prices in October and early November have caused the Company's voluntary production shut-in strategy to be implemented on a number of occasions. For the October 2018 through March 2019 period, Perpetual has fixed the price on 15,000 GJ/d at $1.41/GJ AECO with the remainder of its production sold at daily index prices at the Chicago, Dawn, Empress, Malin and Michcon markets through its 40,000 MMBtu/d market diversification contract. If AECO prices temporarily weaken, Perpetual's fixed price AECO position provides the ability to shut-in production and purchase gas to deliver against pre-sold commitments while preserving reserves and future deliverability capability. Perpetual has costless collar and fixed price WTI oil sales arrangements in place to sell 750 bbl/d at an average ceiling price of US$60.71/bbl for the remainder of 2018. Additionally, Perpetual has fixed the US$/Cdn$ exchange rate on approximately 53% of its US$ denominated sales at a rate of $1.30 for the remainder of 2018.

Cash costs of $15.00 to $15.50/boe are now anticipated for 2018, up slightly from Q3 Guidance, due to the produced water spill remediation costs incurred in the third quarter.

Adjusted funds flow for 2018 is anticipated to be in the $27 to $29 million range ($5 to $7 million for the remainder of 2018), consistent with Q3 Guidance. On a per share basis, adjusted funds flow for 2018 is anticipated to be $0.44 to $0.48 per share.

Guidance assumptions are as follows:

	Q4 Guidance	Q3 Guidance
Exploration and development expenditures (*$ millions*)	**$25 - $26**	$25 - $30
2018 cash costs (*$/boe*)	**$15.00 - $15.50**	$14.00 - $15.00
2018 average daily production (*boe/d*)	**10,250 – 10,750**	10,500 - 11,000
2018 average production mix (*%*)	**17% oil and NGL**	16% oil and NGL

Commodity price assumptions reflect market price levels as follows:

	Q4 Guidance	Q3 Guidance
2018 average NYMEX natural gas price (*US$/MMBtu*)	**$2.97**	$2.85
2018 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$67.11**	$65.24
2018 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($25.68)**	($23.62)
2018 average exchange rate (US$1.00 = Cdn$)	**$1.29**	$1.30

Year end 2018 net debt (net of the estimated market value of the Company's TOU share investment of approximately $35 million), is forecast at $104 - $107 million, up from Q3 Guidance of $98 - $103 million, due to a decrease in the market value of the Company's TOU share investment since the second quarter. Current guidance is based on the following assumptions:

- Net debt at September 30, 2018 of $105.4 million
- Adjusted funds flow for the remainder of 2018 of $5 to $7 million
- Capital spending for the remainder of 2018 of $4 to $5 million
- Decommissioning expenditures for the remainder of 2018 of $0.5 to $1.0 million

On November 7, 2018, the revolving bank debt Borrowing Limit was reduced from $60 million to $55 million by the Company's lenders with the next Borrowing Limit redetermination scheduled on or prior to May 31, 2019. The term of the revolving bank debt has not been extended and will mature on May 31, 2019.

2019 capital spending and production guidance

The Company's Board of Directors has approved a total capital spending program of $21 to $25 million for 2019 to be funded from adjusted funds flow. At least 50% will be spent in Eastern Alberta, primarily targeting heavy oil development at Mannville along with abandonment and reclamation work of up to $2 million to prudently address decommissioning obligations. The remaining 50% of expenditures will be concentrated in East Edson, developing liquids-rich natural gas reserves in the Wilrich formation if AECO forward gas prices support investment in the second half of 2019, or alternatively, will be deployed in an expanded heavy oil drilling program. The Company has minimal capital spending planned for the first half of 2019. The second half program is planned to align operations with higher anticipated commodity prices.

Forecast capital activity in Mannville for 2019 includes the drilling of 10 (10.0 net) new wells, targeting a mix of infill wells and step outs in waterflooded pools as well as open hole multi-lateral wells following up on the success of the 2018 program. Timing for the 2019 program is in the third quarter of 2019 to take advantage of lower drilling, completion, and equipping costs generally realized in the summer in Mannville, as well as the anticipation that heavy oil price differentials will improve through 2019. Additionally, up to 10 shallow gas recompletions are planned to be executed in late 2019, if gas prices improve, to partially offset natural gas declines in Eastern Alberta. Decommissioning expenditures will continue to be focused in the Mannville area and are expected to provide future lease rental and property tax expense reductions while maintaining regulatory compliance. In Eastern Alberta, production is forecast to grow from a range of 1,800 to 1,900 boe/d (54% oil) in 2018 to 2,200 to 2,400 boe/d (61% oil) in 2019.

At East Edson, the Company has budgeted a two (2.0 net) well drilling program to come onstream during the fourth quarter of 2019, as well as capital for a strategic secondary zone recompletion program and maintenance. The two wells will be extended reach horizontal ("ERH") wells, as the performance of the ERH wells drilled in late 2017 and early 2018 indicate improved capital efficiencies over the wells drilled with less than 2,500 meters of lateral length. If AECO forward gas prices normalize above $2.00/Mcf, drilling activities are expected to continue into 2020, in order to ramp up production to again match processing and transportation capacity. Processing capacity at the Company's 100% working interest and operated West Wolf Lake facility is 65 MMcf/d, with an additional 13 MMcf/d of working interest capacity at the non-operated Rosevear plant, plus associated liquids. 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. Natural declines and capital spending deferrals to late 2019 result in lower anticipated 2019 production in East Edson with an average of 7,000 to 7,200 boe/d (10% oil and NGLs). Despite reduced production in East Edson, and a substantially fixed operating cost base, operating costs are forecast to remain in the top quartile at less than $3.25/boe.

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

2019 Exploration and Development Forecast Capital Expenditures

	H1 2019 (*$ millions*)	**# of wells (*gross/net*)**	**H2 2019 (*$ millions*)**	**# of wells (*gross/net*)**
West Central liquids-rich gas	0	0/0.0	12	2/2.0
Eastern Alberta	0	0/0.0	11	10/10.0
Total[(1)]	**0**	**0/0.0**	**23**	**12/12.0**

(1) Excludes budgeted abandonment and reclamation spending of $1.5 to $2.0 million in 2019.

Perpetual expects the 2019 capital program will be funded by adjusted funds flow. Perpetual forecasts average production of 9,200 to 9,600 boe/d, with oil and NGL production growing to represent approximately 22% of the production mix. The Company expects to exit the year at over 11,500 boe/d (80% natural gas) as production ramps up again driven by the second half capital spending program targeting seasonal natural gas price optimization. This represents a reduction in average daily production in 2019 of approximately 11% relative to 2018, but includes a 16% increase in oil and NGL production.

Cash costs of $17.00 to $18.00/boe are forecast for 2019, up approximately 13% to 16% from 2018 guidance due to the impact of 11% lower forecast 2019 production on a substantially fixed operating cost base. Increased oil production in 2019 that is higher cost than compared to natural gas cash costs, is also expected to contribute to the increase in 2019 cash costs per boe.

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%
Empress	7%
Dawn	15%
Michcon	10%
Chicago	24%
Malin	21%
Total natural gas	79%
Natural gas liquids - Condensate(1)	4%
Natural gas liquids - Other(1)	2%
Crude oil(1)(2)	15%
Total	100%

(1) Net of royalties.
(2) For the 2019 calendar year, Perpetual has a costless collar on 500 bbl/d protecting a WTI floor price of US$60.00/bbl with a ceiling price of US$72.40/bbl, along with a 500 bbl/d WCS differential fixed at US$26.83/bbl.

Guidance assumptions are as follows:

	2019 Guidance
Exploration and development expenditures (*$ millions*)	**$21 - $25**
2019 cash costs (*$/boe*)	**$17.00 - $18.00**
2019 average daily production (*boe/d*)	**9,200 – 9,600**
2019 average production mix (*%*)	**22% oil and NGL**

Commodity price assumptions reflect market price levels as follows:

	2019 Guidance
2019 average NYMEX natural gas price (*US$/MMBtu*)	**$2.89**
2019 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$69.81**
2019 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($29.16)**
2019 average exchange rate (US$1.00 = Cdn$)	**$1.30**

Year end 2019 net debt (net of the estimated market value of the Company's TOU share investment of approximately $35 million), is forecast at $103 to $108 million, with an estimated net debt to trailing twelve months adjusted funds flow ratio of approximately 4.3 times. Current guidance is based on the following assumptions:

- Net debt at December 31, 2018 of $104 to $107 million
- Adjusted funds flow for 2019 of $22 to $27 million ($0.36/share to $0.44/share)
- Capital spending for 2019 of $21 to $25 million
- Decommissioning expenditures for 2019 of $1.5 to $2.0 million

The following sensitivities can be applied to estimate changes to projected 2019 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 Calendar 2019 NYMEX Daily Index price, adjusted funds flow increases or decreases by $4.8 million;
- For every US$2.50/bbl increase or decrease in the Calendar 2019 WTI light oil price, adjusted funds flow increases or decreases by $1.4 million;
- For every 2.5 MMcf/d increase or decrease in average natural gas production, adjusted funds flow increases or decreases by $1.4 million; and
- For every 250 bbl/d increase or decrease in average crude oil and NGL production, adjusted funds flow increases or decreases by $4.2 million.

THIRD QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Exploration and development	**4,338**	25,384	**20,922**	53,928
Other	**5**	8	**349**	60
Capital expenditures	**4,343**	25,392	**21,271**	53,988
Acquisitions	**1,261**	224	**1,871**	432
Net payments (proceeds) on dispositions	**3,080**	456	**(3,616)**	1,020
Total	**8,684**	26,072	**19,526**	55,440

Exploration and development spending by area

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
West Central	**181**	25,368	**9,430**	47,341
Eastern Alberta	**4,157**	16	**11,492**	6,587
Total	**4,338**	25,384	**20,922**	53,928

Wells drilled by area

	Three months ended September 30,		Nine months ended September 30,	
(gross/net)	**2018**	2017	**2018**	2017
West Central	**-/-**	5/4.4	**1/1.0**	11/10.4
Eastern Alberta	**3/3.0**	-/-	**6/6.0**	5/4.3
Total	**3/3.0**	5/4.4	**7/7.0**	16/14.7

Perpetual's exploration and development spending in the third quarter of 2018 was $4.3 million, 83% lower than the comparative period in 2017. Capital expenditures were directed almost entirely to Eastern Alberta and included the drilling of three (3.0 net) new heavy oil horizontal wells, along with a fourth well that was re-entered at Mannville. Two of the wells were tied-in to production at the end of the third quarter, and the remaining two came online during the first week of October. The third quarter 2018 drills were development wells targeting higher pressure areas of existing pools under waterflood, and production results to date are consistent with expectations. The fourth well was a re-entry to add three unlined laterals to an exploratory single-leg well drilled in 2017, to evaluate the application of multi-lateral drilling technology for the large resource in place in the low recovery Mannville oil pool. Initial results are positive, and the Company will continue to monitor performance. Capital was also invested in the installation of a one-megawatt electricity generator at the Mannville plant site. The project will utilize fuel gas produced from the Mannville gas plant and convert it to electricity which will be sold on the grid, effectively increasing the value of Mannville gas production. The generator was sourced from internal inventory, minimizing the net cost of the project. The power project came online in the first week of October. The economics of an expansion to a five-megawatt generating capacity is being evaluated.

Spending at the East Edson property in West Central Alberta represented just 4% of total exploration and development expenditures in the third quarter of 2018, and consisted primarily of maintenance activities associated with reconfiguring equipment for higher NGL recoveries. East Edson capital activity for the nine months ended September 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") natural gas well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The well drilled during the first quarter is expected to be frac'd and tied-in to production during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

For the nine months ended September 30, 2018, spending in Eastern Alberta consisted of a six well (6.0 net) multi-lateral horizontal drilling program, one waterflood injector well conversion, one water disposal well conversion and associated facilities on the Company's Mannville heavy oil properties. The disposal facility is working as intended, and is contributing to operating cost improvements. Two of the wells drilled during the third quarter offset a water injector well converted in December of 2017. The wells encountered high pressures and are producing at budgeted oil rates, further validating the success of the Mannville waterfloods.

During the third quarter of 2018, Perpetual spent $1.3 million to acquire the remaining 33% working interest in a Mannville heavy oil pool, adding approximately 65 boe/d of production.

Dispositions

Proceeds (payments) on dispositions

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Proceeds from retained shallow gas marketing arrangements(1)	**–**	–	–	869
Payments on retained shallow gas marketing arrangements(1)	**(3,084)**	(950)	**(8,540)**	(2,819)
Net proceeds (payments) on dispositions	**(3,080)**	(456)	**3,616**	(1,020)

Gain (loss) on dispositions

($ thousands)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Carrying amount of PP&E and E&E disposed, net of ARO	**–**	–	**(11,415)**	(8)
Realized gain (loss) from retained shallow gas marketing arrangements[1]	**–**	–	**(874)**	869
Unrealized loss on retained shallow gas marketing arrangements[1]	**–**	(2,072)	**–**	(6,592)
Gain (loss) on dispositions	**4**	(1,578)	**(133)**	(4,801)

(1) Related to the Shallow Gas Disposition.

Dispositions during the nine months ended September 30, 2018 included the sale of non-core royalty interests and exploration and evaluation properties for gross proceeds of $12.1 million, resulting in a net gain on oil and gas properties of $0.7 million. Included in the gain was $0.4 million in liabilities related to decommissioning obligations associated with the sale of non-core properties.

On October 1, 2016, Perpetual sold 5,900 boe/d of mature shallow gas assets in east central and northeast Alberta for nominal cash consideration that also included retained marketing arrangements whereby the Company provided natural gas floor price protection at $2.58/GJ to the purchaser and retained price participation to the extent average monthly AECO prices exceed $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. Realized and unrealized gains and losses on these marketing arrangements have been recognized as adjustments to gains/losses on dispositions and included as cash flows from investing activities in the consolidated statement of cash flows. During the first quarter of 2018, Perpetual fixed the cost of the floor price protection for the remaining period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million. Remaining payments of $3.1 million were made during the third quarter (nine months ended September 30, 2018 – $8.5 million) related to the fixed floor price protection. The retained marketing arrangements have since expired.

Expenditures on decommissioning obligations

During the three months ended September 30, 2018, Perpetual spent $0.3 million (Q3 2017 – $0.9 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, five reclamation certificates were received from the Alberta Energy Regulator during the third quarter of 2018 (Q3 2017 – two) which will result in the cessation of associated property tax and surface lease expenses. For the nine months ended September 30, 2018, Perpetual spent $1.2 million (2017 – $1.4 million) on abandonment and reclamation projects and received 18 reclamation certificates, compared to 29 in the prior year period. Perpetual will continue to execute its internally managed asset retirement program at Mannville in the final quarter of 2018.

Operating netbacks

The following table highlights Perpetual's operating netbacks for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30, 2018			Three months ended September 30, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue [1]	**13,994**	**6,510**	**20,504**	14,921	5,104	20,026
Realized gains on derivatives [2]	**–**	**–**	**45**	–	–	665
Royalties	**(1,967)**	**(691)**	**(2,658)**	(1,841)	(773)	(2,614)
Production and operating expenses	**(1,725)**	**(3,577)**	**(5,302)**	(1,944)	(1,382)	(3,326)
Transportation costs	**(1,207)**	**(383)**	**(1,590)**	(921)	(410)	(1,331)
Total operating netback	**9,095**	**1,859**	**10,999**	10,215	2,539	13,420

	Nine months ended September 30, 2018			Nine months ended September 30, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue [1]	**47,902**	**16,716**	**64,618**	41,442	16,469	57,912
Realized gains on derivatives [2]	**–**	**–**	**1,784**	–	–	1,574
Royalties	**(6,545)**	**(1,766)**	**(8,311)**	(7,376)	(1,946)	(9,322)
Production and operating expenses	**(5,562)**	**(8,816)**	**(14,378)**	(6,159)	(6,402)	(12,561)
Transportation costs	**(3,531)**	**(1,048)**	**(4,579)**	(2,290)	(1,282)	(3,572)
Total operating netback	**32,264**	**5,086**	**39,134**	25,617	6,839	34,031

(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 certain financial prompt month price optimization contracts.

	Three months ended September 30, 2018			Three months ended September 30, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**7,695**	**1,874**	**9,569**	8,313	2,017	10,330
Total petroleum and natural gas revenue	**19.77**	**37.76**	**23.29**	19.51	27.50	21.07
Realized gains on derivatives	**–**	**–**	**0.05**	–	–	0.70
Royalties	**(2.78)**	**(4.01)**	**(3.02)**	(2.41)	(4.16)	(2.75)
Production and operating expenses	**(2.44)**	**(20.75)**	**(6.02)**	(2.54)	(7.45)	(3.50)
Transportation costs	**(1.71)**	**(2.22)**	**(1.81)**	(1.20)	(2.21)	(1.40)
Total operating netback	**12.84**	**10.78**	**12.49**	13.36	13.68	14.12

	Nine months ended September 30, 2018			Nine months ended September 30, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**9,168**	**1,797**	**10,965**	7,212	2,028	9,240
Total petroleum and natural gas revenue	**19.14**	**34.06**	**21.59**	21.05	29.75	22.96
Realized gains on derivatives	**–**	**–**	**0.59**	–	–	0.62
Royalties	**(2.62)**	**(3.60)**	**(2.78)**	(3.75)	(3.52)	(3.70)
Production and operating expenses	**(2.22)**	**(17.96)**	**(4.80)**	(3.13)	(11.56)	(4.98)
Transportation costs	**(1.41)**	**(2.14)**	**(1.53)**	(1.16)	(2.32)	(1.42)
Total operating netback	**12.89**	**10.36**	**13.07**	13.01	12.35	13.48

Production and operating expenses increased in the third quarter of 2018 due to remediation costs incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring third-party processing fee adjustment received in the prior year period. Transportation costs were higher in the third quarter due to increased firm natural gas pipeline capacity commencing in the fourth quarter of 2017.

Perpetual's operating netback of $11.0 million ($12.49/boe) in the third quarter of 2018 decreased 18% from $13.4 million ($14.12/boe) in the comparative period of 2017. This decrease was due to the 7% decrease in production caused by natural declines at East Edson, combined with a 12% decrease in operating netback per boe. The lower operating netback per boe in the third quarter of 2018 reflected a 7% increase in realized revenue per boe due to improved crude oil and NGL pricing. Higher realized selling prices were more than offset by the associated increase in royalties, combined with higher operating costs related to the non-recurring items.

Perpetual's operating netback of $39.1 million ($13.07/boe) for the nine months ended September 30, 2018 increased 15% from $34.0 million ($13.48/boe) in the comparative period of 2017. This increase was due to the 19% increase in production, offset partially by the modest decrease in operating netback per boe.

Production

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Natural gas (*MMcf/d*)				
Eastern Alberta	**5.2**	6.4	**5.2**	6.4
West Central	**41.7**	45.4	**50.0**	39.5
Total natural gas(1)	**46.9**	51.8	**55.2**	45.9
Crude oil (*bbl/d*)				
Eastern Alberta(2)	**1,009**	956	**937**	949
West Central	**13**	22	**28**	19
Total crude oil	**1,022**	978	**965**	968
Total NGL (*bbl/d*)(3)	**730**	733	**794**	627
Total production (*boe/d*)	**9,569**	10,330	**10,965**	9,240

(1) Natural gas production yielded a heat content of 1.17 GJ/Mcf (Q3 2017 – 1.17) for the three months ended and 1.17 GJ/Mcf for the nine months ended September 30, 2018 (2017 – 1.16), resulting in higher realized natural gas prices per Mcf. See "Commodity Prices" – Average Perpetual prices for selling price premium to AECO Daily Index.

(2) Primarily Mannville heavy oil.

(3) Primarily West Central liquids-rich gas.

Third quarter production averaged 9,569 boe/d, down 7% from 10,330 boe/d in the comparative period of 2017. The decrease was driven by approximately 700 boe/d of production that was shut-in at East Edson throughout the second and third quarters at the request of the Alberta Energy Regulator after the operator of record, Sequoia, filed for bankruptcy. On October 15, 2018, Perpetual submitted a property claim application to the bankruptcy trustee requesting the transfer of the four well pad operating license back to Perpetual. The bankruptcy trustee has stated they will cooperate with the application, and Perpetual anticipates that production from these wells will resume by early 2019. Compared to the second quarter of 2018, production was down 10%. The decrease was driven by natural declines in East Edson resulting from limited capital investment during 2018 in response to low AECO natural gas prices. There were no voluntary market related shut-ins of natural gas production during the third quarter.

NGL yields at East Edson were consistent with the second quarter of 2018 at approximately 17 bbls per MMcf of natural gas, an increase from 16 bbls per MMcf in the third quarter of 2017, due to the reconfiguration of plant processing equipment and higher NGL production from wells tied-in and reactivated during the first quarter of 2018.

Crude oil production in Eastern Alberta was 7% higher than the second quarter of 2018. The increased production was due to the combined impact of the Mannville heavy oil working interest acquisition and lower base declines at Mannville due to waterflood operations. At Mannville, waterflood performance continues to be a focus with base production increasing by approximately 8% throughout the year. Production from new heavy oil wells drilled did not commence until late in the quarter.

For the nine months ended September 30, 2018, production increased by 19% to 10,965 boe/d compared to 9,240 boe/d in the prior year period. Production reached peak levels in the first quarter of 2018, and has since declined as further drilling in East Edson has been deferred pending higher natural gas prices.

Production at East Edson is expected to continue to decline in the fourth quarter until the well drilled in the first quarter of 2018 is frac'd and tied in for production, and the shut-in four well East Edson pad is restarted.

Commodity Prices

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Reference prices				
NYMEX Daily Index (*US$/MMBtu*)	**2.90**	3.00	**2.90**	3.17
AECO Daily Index (*$/GJ*)	**1.13**	1.38	**1.41**	2.19
AECO Daily Index ($/Mcf)(1)	**1.19**	1.46	**1.49**	2.31
Alberta Gas Reference Price (*$/GJ*)(2)	**1.04**	1.58	**1.22**	2.15
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**69.50**	48.20	**66.75**	49.47
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(22.25)**	(9.94)	**(21.93)**	(11.88)
WCS average (Cdn*$/bbl*)(3)	**61.90**	47.83	**57.82**	49.24
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**1.19**	1.46	**1.49**	2.31
Heat content premium(4)	**0.13**	0.15	**0.16**	0.24
Market diversification contracts	**1.17**	–	**0.84**	–
Realized gains (losses) on financial and physical gas derivatives	**0.29**	1.28	**0.11**	1.09
Realized gains (losses) on prompt month price optimization	**0.05**	0.10	**0.09**	0.01
Realized natural gas price (*$/Mcf*)(5)	**2.83**	2.99	**2.69**	3.65
Percent of AECO Daily Index	**238**	205	**181**	158
Realized oil price (*$/bbl*)(5)	**48.57**	43.01	**50.06**	39.86
Natural gas liquids ("NGL") (*$/bbl*)	**56.02**	39.06	**58.19**	43.59

(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$1.31 for the three months ended September 30, 2018 (Q3 2017 – $1.25) and $1.29 for the nine months ended September 30, 2018 (2017 – $1.31).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher heat content. For the three and nine months ended September 30, 2018, Perpetual received an 11% premium to the AECO Daily Index (three and nine months ended September 30, 2017 – 10%).
(5) Realized natural gas and oil 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.

Despite increased demand due to a colder year-over-year winter, a warmer year-over-year May and September 2018, and higher liquefied natural gas ("LNG") and Mexican exports; 7.4 Bcf/d of higher United States production in the nine months ended September 30, 2018 versus the prior year period caused NYMEX natural gas prices to decrease 9% from US$3.17/MMBtu for the nine months ended September 30, 2017 to an average of US$2.90/MMBtu for the nine month period ended September 30, 2018. In comparison, the average AECO Daily Index price decreased 35% from $2.19/GJ for the nine months ended September 30, 2017 to $1.41/GJ for the nine month period ended September 30, 2018. In mid-2017, AECO prices became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin outpaced access to markets outside of Western Canada and local market demand, aggravated by the management of pipeline maintenance activities.

The increase of WTI to US$66.75/bbl for the nine month period ended September 30, 2018 from US$49.47/bbl for the nine months ended September 30, 2017 was related to the reduction in global oil inventories in 2018, stemming from the OPEC production cuts that began January 1, 2017, continued steep declines in Venezuelan production, and the pending reinstatement of sanctions on Iranian production by the United States beginning in November 2018. The WCS differential widened from an average US$11.88/bbl in the first nine months of 2017 to US$21.93/bbl in the same period of 2018, due to increased heavy oil and bitumen production predominately related to the ramp up of Suncor's Fort Hills oil sands project in Q3 2018, combined with pipeline capacity constraints that restricted access to markets outside of Western Canada.

Perpetual's realized natural gas price, including derivatives, decreased 5% to $2.83/Mcf for the third quarter of 2018 from $2.99/Mcf in the comparative period of 2017, but represented a 138% premium over the AECO Daily Index price compared to 105% in the prior year period. Realized gains on financial and physical gas derivatives, along with prompt month price optimization operations added $0.34/Mcf to the realized price in the third quarter of 2018 (Q3 2017 – $1.38/Mcf). The market diversification contract added $1.17/Mcf (Q3 2017 – nil) on the relative strength of NYMEX daily index prices compared to AECO. During the third quarter of 2018, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, consistent with the comparative period of 2017. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018, and 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.

Perpetual's realized oil price of $48.57/bbl was 13% higher than the third quarter of 2017 and included realized losses on crude oil derivative contracts of $0.8 million ($8.96/bbl) on 750 bbl/d of production. Realized prices in the third quarter of 2017 were reduced by $3.52/bbl associated with realized hedging losses in the period.

Perpetual's realized NGL price for the third quarter of 2018 reached $56.02/bbl, up 43% from the third quarter of 2017, reflecting an increase in all NGL component prices which closely correlate with the 44% increase in WTI light oil prices over the prior year period. Perpetual's average NGL sales composition for the third quarter ended September 30, 2018 consisted of 61% condensate, comparable to the prior year period.

Revenue

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Petroleum and natural gas revenue				
Natural gas(1)	**11,330**	13,205	**38,035**	38,435
Oil	**5,410**	4,186	**13,963**	12,017
NGL	**3,764**	2,635	**12,620**	7,460
Total petroleum and natural gas revenue	**20,504**	20,026	**64,618**	57,912
Realized gains (losses) on derivatives(2)	**45**	665	**1,784**	1,574
Realized revenue	**20,549**	20,691	**66,402**	59,486
Unrealized gains (losses) on derivatives	**(34)**	(96)	**(5,138)**	4,279
Total revenue	**20,515**	20,595	**61,264**	63,765
Realized revenue *($/boe)*	**23.34**	21.77	**22.18**	23.58
Total revenue *($/boe)*	**23.30**	21.67	**20.47**	25.28

(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 September 30, 2018 of $20.5 million increased 2% from the third quarter of 2017 despite a 7% decrease in average daily production. For the nine month period ended September 30, 2018, P&NG revenue increased by 12% compared to the prior year period, following the 19% increase in average daily production over the same period.

Natural gas revenue, before derivatives, of $11.3 million in the third quarter of 2018 comprised 55% (Q3 2017 – 66%) of total P&NG revenue while natural gas production was 81% (Q3 2017 – 84%) of total production. Natural gas revenue decreased 14% from $13.2 million in the third quarter of 2017, reflecting the impact of the 9% decrease in natural gas production volumes driven by natural declines following limited capital investment in East Edson during the second and third quarters of 2018. Perpetual's market diversification contract contributed $5.0 million of incremental revenue ($1.17/Mcf) over the AECO Daily Index price in the quarter ($12.7 million and $0.84/Mcf for the nine months ended September 30, 2018). For the nine month period ended September 30, 2018, natural gas revenue decreased by 1% compared to the prior year period, due primarily to the 35% decline in AECO Daily Index prices which more than offset the 20% increase in natural gas production over the same period.

Oil revenue of $5.4 million represented 26% (Q3 2017 – 21%) of total P&NG revenue while oil production was 11% (Q3 2017 – 9%) of total production. Oil revenue was 29% higher than the same period in 2017 due to the 13% increase in realized oil prices combined with the 4% increase in crude oil production. The improved WCS average prices are a function of a higher WTI US$ benchmark price and stronger US dollar, which more than offset the wider WCS differential compared to the prior year period. For the nine month period ended September 30, 2018, oil revenue increased by 16% compared to the prior year period, due primarily to the 17% increase in WCS prices with steady oil production over the same period.

NGL revenue for the third quarter of 2018 of $3.8 million represented 19% (Q3 2017 – 13%) of total P&NG revenue while NGL production was just 8% (Q3 2017 – 7%) of total Company production. NGL revenue increased by 43% over the prior year period while NGL production remained flat, reflecting a 43% increase in NGL prices compared to the prior year period. For the nine month period ended September 30, 2018, NGL revenue increased by 69% compared to the prior year period, due to the 27% increase in production combined with a 33% increase in realized NGL prices. The increase in production over the nine months ended September 30, 2017 reflected increased natural gas production at East Edson and higher NGL yields related to process optimization work at the Company's 100% owned and operated gas plant.

Realized gains on derivatives totaled $0.1 million for the third quarter of 2018, compared to gains of $0.7 million for the same period of 2017. The realized gain in the current period was comprised of $0.9 million from natural gas derivatives (Q3 2017 – $1.0 million), offset partially by losses of $0.8 million from oil derivatives (Q3 2017 – $0.3 million).

Perpetual recorded minimal unrealized losses on derivatives during the third quarter of 2018 and 2017. 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. Commodity price management contracts are actively managed in accordance with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Crown	**573**	574	**2,001**	1,806
Freehold and overriding[(1)]	**2,085**	2,040	**6,310**	7,516
Total	**2,658**	2,614	**8,311**	9,322
Crown (*% of P&NG revenue*)	**2.8**	2.9	**3.1**	3.1
Freehold and overriding (*% of P&NG revenue*)	**10.2**	10.2	**9.8**	13.0
Total (*% of P&NG revenue*)	**13.0**	13.1	**12.9**	16.1
$/boe	**3.02**	2.75	**2.78**	3.70

(1) Includes $1.3 million in gross overriding royalty payments at East Edson for the three months ended September 30, 2018 (Q3 2017 – $1.2 million) and $4.1 million for the nine months ended September 30, 2018 (2017 – $5.3 million).

Royalty expenses for the third quarter of 2018 were $2.7 million, consistent with the comparable period of 2017. Similarly, the combined average royalty rate on P&NG revenue remained consistent with the prior year period at approximately 13%.

For the nine months ended September 30, 2018, sharply lower Alberta Gas Reference prices (43% decline) and AECO Daily Index prices (35% decline) used to calculate crown and freehold natural gas royalties respectively, contributed to most of the decrease in royalty expense, despite the 20% increase in natural gas production over the same period. Pursuant to Perpetual's East Edson agreements, the partner is entitled to a gross overriding royalty equivalent to a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL's on a monthly basis. The East Edson royalty is taken in kind, but calculated based on the AECO Daily Index natural gas price. As East Edson natural gas production has increased by 27% for the nine months ended September 30, 2018 compared to the prior year period, the fixed nature of the gross overriding royalty has resulted in a decreased expense on a percentage of revenue and unit-of-production basis.

Production and operating expenses

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Production and operating expenses	**5,302**	3,326	**14,378**	12,561
$/boe	**6.02**	3.50	**4.80**	4.98

Total production and operating expenses were up 72% on a unit-of-production basis to $6.02/boe for the third quarter of 2018, compared to $3.50/boe for the comparable period of 2017. The increase was driven by remediation costs of $0.8 million ($0.91/boe) incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring adjustment in the prior year period associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. Remediation work related to the pipeline break at Mannville was completed in early October. On an absolute dollar basis, production and operating costs were up by $2.0 million, despite the 7% decrease in production, largely related to the non-recurring items noted above. West Central operating costs decreased by 4% to $2.44/boe in the third quarter of 2018 (Q3 2017 – $2.54/boe). The third quarter of 2018 also saw modestly higher well servicing requirements in the Mannville heavy oil operations which increased Eastern Alberta operating costs compared to the prior year period, while negatively affecting production volumes.

Transportation costs

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Transportation costs	**1,590**	1,331	**4,579**	3,572
$/boe	**1.81**	1.40	**1.53**	1.42

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 third quarter of 2018 were $1.6 million, up 19% from the prior year period due to the increase in firm natural gas transportation commitments at East Edson to 78 MMcf/d that commenced in December 2017. Transportation costs averaged $1.71/boe at West Central compared to $2.22/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.81/boe in the third quarter, up 29% from the prior year period due to the impact of increased fixed firm capacity transportation costs against lower production. During the third quarter of 2018, the Company was not able to mitigate any of its excess firm transportation costs.

Gas over bitumen

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Gas over bitumen royalty credit	**191**	353	**744**	1,965
Payments on gas over bitumen royalty financing[(1)]	**(179)**	(558)	**(878)**	(2,084)
Gas over bitumen, net of payments	**12**	(205)	**(134)**	(119)
$/boe	**0.01**	(0.22)	**(0.04)**	(0.05)

(1) At September 30, 2018, the fair value of the gas over bitumen royalty financing was estimated to be $1.8 million (December 31, 2017 – $2.7 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 third quarter of 2018, Perpetual recorded $0.2 million in gas over bitumen revenue, a 46% decrease from $0.4 million in the same period of 2017. The decrease in gas over bitumen revenue is attributable to the 34% decline in Alberta gas reference prices, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the third quarter of 2018 funded payments of $0.2 million (Q3 2017 – $0.6 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 was recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenue 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 third quarter of 2018, the gas over bitumen royalty financing obligation was reduced by $0.3 million, comprised of payments of $0.2 million and an unrealized gain of $0.1 million. The gain has been included in non-cash finance expense and represents a decrease in the fair value of the gas over bitumen royalty financing obligation as a result of lower forecasted natural gas reference prices.

Exploration and evaluation

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2018**	2017	**2018**	2017
Lease rentals	**175**	178	**517**	547
Geological and geophysical costs	**78**	–	**78**	(22)
Lease expiries (non-cash)	**–**	784	**–**	2,602
Total exploration and evaluation	**253**	962	**595**	3,127

Exploration and evaluation ("E&E") costs include lease rentals on undeveloped acreage, geological and geophysical costs and the write-down of carrying costs related to lease expiries. Comparable with the prior year period, Perpetual recorded lease rentals of $0.2 million for the three months ended September 30, 2018.

General and administrative ("G&A") expenses

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2018**	2017	**2018**	2017
Cash G&A expense	**3,824**	3,912	**11,213**	11,670
Overhead recoveries	**(428)**	(1,062)	**(1,376)**	(2,577)
Total G&A expense	**3,396**	2,850	**9,837**	9,093
$/boe	**3.86**	3.00	**3.29**	3.60

During the third quarter of 2018, cash G&A expense was $3.8 million, a slight decrease from the prior year period of $3.9 million. Cash G&A expense increased by $0.3 million over the second quarter of 2018, due primarily to Sequoia litigation defence costs. The Company expects the majority of future defence costs will be covered by insurance. Compared to the prior year period, third quarter 2018 overhead recoveries decreased by 60% as a result of reduced capital spending, combined with a reduction in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.86/boe for the three months ended September 30, 2018 was up 29% from the prior year period due to the impact of decreasing production. For the nine month period, G&A expense decreased from $3.60/boe in 2017 to $3.29/boe in 2018 due to the 19% increase in average daily production.

Share-based payments

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2018**	2017	**2018**	2017
Share-based payments expense (non-cash)	**508**	906	**2,007**	3,423
$/boe	**0.58**	0.95	**0.67**	1.36

Non-cash share-based payments expense for the three months ended September 30, 2018 was $0.5 million, down 44% compared to the same period in 2017 due to a reduction in the value of outstanding share-based payment awards.

Depletion and depreciation

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2018**	2017	**2018**	2017
Depletion and depreciation	**8,262**	8,967	**27,169**	24,021
$/boe	**9.38**	9.44	**9.08**	9.52

Perpetual recorded $8.3 million of depletion and depreciation expense for the three months ended September 30, 2018, a decrease of 8% from $9.0 million recorded in the prior year period. The decrease reflects the 7% decline in production volumes compared to the prior year period, along with a 1% reduction in the depletion rate following the success of the Company's 2017 capital expenditure program that added proved plus probable reserves at a cost of $5.98/boe in 2017.

Impairment

E&E assets are tested for impairment when there is an indication that a particular project may be impaired. Examples of indicators of impairment include the decision to no longer pursue exploration and development of undeveloped lands, an expiry of the rights to explore in an area, or failure to receive regulatory approval. In addition, E&E assets are assessed for impairment upon their reclassification to producing assets (oil and natural gas interests in PP&E). In assessing the impairment of E&E assets, the carrying value of the assets are compared to their estimated recoverable amount and the impairment of E&E assets is recognized in the condensed interim consolidated statements of loss and comprehensive loss.

In the third quarter of 2018, Perpetual determined that no additional capital would be spent to hold existing leases on its Waskahigan Duvernay prospect. As a result, the carrying value of the Waskahigan area was written down to its estimated recoverable amount of $1.3 million, resulting in an impairment charge of $7.2 million (Q3 2017 – nil) on E&E assets at September 30, 2018. On November 1, 2018, Perpetual sold its Waskahigan area interests to a third party for cash consideration of $1.3 million and retained a 1% gross overriding royalty to maintain exposure to future drilling conducted by the purchaser.

Finance expenses

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Cash interest expense and income				
Interest on revolving bank debt	**621**	380	**1,593**	764
Interest on TOU share margin demand loan	**130**	159	**440**	460
Interest on term loan	**911**	695	**2,729**	1,549
Interest on senior notes	**711**	764	**2,154**	3,043
Dividend income from TOU share investment	**(166)**	–	**(451)**	–
Total cash interest expense and income	**2,207**	1,998	**6,465**	5,816
Non-cash finance expense				
Amortization of debt issue costs	**247**	139	**764**	422
Accretion on decommissioning obligations	**210**	185	**625**	571
Change in fair value of gas over bitumen royalty financing	**(106)**	(653)	**(38)**	(1,859)
Change in fair value of TOU share put option margin loans	**–**	(48)	**–**	1,377
Total non-cash finance expense	**351**	(377)	**1,351**	511
Finance expenses recognized in net loss	**2,558**	1,621	**7,816**	6,327

Total cash interest expense and income of $2.2 million for the three months ended September 30, 2018 was 10% higher than the prior year period (Q3 2017 – $2.0 million) due to increased debt levels, partially offset by dividend income of $0.2 million ($0.10 per TOU share) received from the TOU share investment during the third quarter of 2018 (Q3 2017 – nil).

Total non-cash finance expense for the three months ended September 30, 2018 was $0.4 million (Q3 2017 – income of $0.4 million). A decrease in the fair value of the gas over bitumen royalty financing was recorded in both periods due to lower AECO future natural gas prices, resulting in a fair value at September 30, 2018 of $1.8 million. The change in the fair value of TOU share put option margin loans recorded in the third quarter of 2017 did not re-occur in 2018, as these loans were refinanced without embedded put option derivatives during the third quarter of 2017.

Change in fair value of TOU share investment

During the three months ended September 30, 2018, Perpetual recorded a loss of $1.2 million related to the change in fair value of the TOU share investment. This change was due to a 3% decrease in the TOU share price over the third quarter. At September 30, 2018, the Company owned 1.66 million TOU shares (December 31, 2017 – 1.67 million shares) having a quoted market value of $37.7 million (December 31, 2017 – $38.0 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 longer term financial sustainability.

On November 7, 2018, the revolving bank debt Borrowing Limit was reduced from $60 million to $55 million by the Company's lenders with the next Borrowing Limit redetermination scheduled on or prior to May 31, 2019. The term of the revolving bank debt has not been extended and will mature on May 31, 2019. If the repayment term of the revolving bank debt is not extended at that time, all outstanding advances will become payable on May 31, 2019. The repayment term has not been extended due to uncertainties associated with the Sequoia litigation and pending the repayment of the $14.6 million unsecured senior notes that mature on July 23, 2019 (the "2019 Senior Notes"). Please refer to the "Third Quarter 2018 Highlights" section of this MD&A for additional discussion of the Sequoia litigation. The 2019 Senior Notes may be repaid prior to maturity at no penalty, upon provision of 30 days' notice to note holders.

After giving effect to the $5 million reduction in the Borrowing Limit, Perpetual had available liquidity at September 30, 2018 of $30.9 million, comprised of an unutilized Borrowing Limit of $8.9 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $22.0 million. Perpetual intends to continue the advancement of its Sequoia litigation defence while considering options available to repay the 2019 Senior Notes, including raising proceeds from the refinancing or sale of its Tourmaline share investment, or the sale or monetization of other assets. 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 these financial statements.

Capital management

($ thousands, except as noted)	**September 30, 2018**	December 31, 2017
Revolving bank debt	**42,431**	31,581
Term loan, measured at principal amount	**45,000**	45,000
TOU share margin demand loan, measured at principal amount	**15,681**	18,490
Senior notes, measured at principal amount	**32,490**	32,490
TOU share investment[1]	**(37,675)**	(37,985)
Net working capital deficiency[2]	**7,484**	16,404
Net debt[2]	**105,411**	105,980
Shares outstanding at end of period (*thousands*)[3]	**60,524**	59,263
Market price at end of period (*$/share*)	**0.31**	1.10
Market value of shares	**18,762**	65,189
Enterprise value[2]	**124,173**	171,169
Net debt as a percentage of enterprise value	**85**	62
Trailing twelve months adjusted funds flow[2]	**34,644**	31,115
Net debt to trailing twelve months adjusted funds flow	**3.0 times**	3.4 times

(1) The TOU share investment is based on the September 30, 2018 closing price per the Toronto Stock Exchange ($22.74 per share) and 1.66 million TOU shares held (December 31, 2017 – 1.67 million TOU shares held with a closing price of $22.78 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At September 30, 2018, Perpetual had total net debt of $105.4 million, down $0.6 million from December 31, 2017, as net cash flow from operations and net proceeds from non-core asset sales exceeded capital expenditures and acquisitions during the year-to-date period. The net working capital deficiency of $7.5 million at September 30, 2018 decreased by $8.9 million from December 31, 2017, due to reduced capital expenditures during the third quarter of 2018 compared to the fourth quarter of 2017, resulting in lower payables at September 30, 2018 compared to December 31, 2017. The decrease in the net working capital deficiency was funded by a corresponding increase in revolving bank debt.

As at September 30, 2018, 60% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved during the nine months ended September 30, 2018 to 3.0 times at September 30, 2018 (December 31, 2017 – 3.4 times).

TOU share margin demand loan

At September 30, 2018, Perpetual had a $15.6 million TOU share margin demand loan ($15.7 million principal amount) secured by 1.66 million TOU shares. On July 31, 2018, the TOU share margin demand loan was entered into with the same lender, having similar terms and conditions as the previous TOU share margin loan. 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 September 30, 2018, the Lending Ratio was 42% of the closing market value of the pledged TOU shares. The TOU share margin demand loan is designated as a financial liability for accounting purposes and measured at amortized cost.

During the nine months ended September 30, 2018, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin loan.

The effective interest rate on the TOU share margin demand loan as at September 30, 2018 was 4.1%. For the period ended September 30, 2018, if interest rates changed by 1%, with all other variables held constant, the impact on annual interest expense and net loss would be $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 September 30, 2018.

Revolving bank debt

As at September 30, 2018, the Company had borrowed $42.4 million (December 31, 2017 – $31.6 million) and issued letters of credit of $3.7 million (December 31, 2017 – $3.9 million) under its reserve-based revolving credit facility (the "Credit Facility"). 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%. The effective interest rate on the Credit Facility at September 30, 2018 was 4.9%. For the period ended September 30, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.4 million (Q3 2017 – $0.3 million).

On November 7, 2018, the Borrowing Limit on the Credit Facility was reduced from $60 million to $55 million, following a reduction in the Borrowing Limit on May 7, 2018 from $65 million to $60 million, with the next semi-annual Borrowing Limit redetermination scheduled on or prior to May 31, 2019. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on May 31, 2019. As the Credit Facility now matures in less than one year, it has been presented as a current liability on the condensed interim consolidated statement of financial position as at September 30, 2018.

The Credit Facility is secured by general, first lien security agreements covering all of the Company's assets, 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 pay dividends on or repurchase its common shares.

At September 30, 2018, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

On March 14, 2017, Perpetual entered into the term loan which included the issuance of 5.4 million warrants to purchase common shares.

($ thousands)	**September 30, 2018**	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**368**	363
Balance, end of period	**$ 43,601**	$ 43,233

The term loan matures on March 14, 2021 and bears interest at 8.1% per annum 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 not repay the term loan prior to the second anniversary thereof, except with payment of a make whole premium.

The term loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and covenants as the Credit Facility. The term loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility, 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 September 30, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			September 30, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 senior notes	July 23, 2019	8.75%	**14,572**	**14,521**	14,572	14,476
2022 senior notes	January 23, 2022	8.75%(1)	**17,918**	**17,305**	17,918	17,204
			$ 32,490	**$ 31,826**	$ 32,490	$ 31,680

(1) Annual interest rate through to January 23, 2018 was 9.75% and 8.75% thereafter.

The 2022 senior notes bear a fixed rate of 8.75% and have identical covenants and rights as the existing 2019 senior notes.

As the 2019 senior notes now mature in less than one year, they have been presented as a current liability on the condensed interim consolidated statement of financial position as at September 30, 2018.

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. At any time prior to three years before the senior note maturity date, the Company can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value. Within three years of maturity, the Company may redeem up to 100 percent of the senior notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100 percent of the senior notes at the principal amount.

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 percent of TTM EBITDA from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100 percent 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 percent of the fair market value of any equity contributions made to the Company.

At September 30, 2018 the senior notes are presented net of $0.7 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At September 30, 2018, 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 September 30, 2018 there were 60.5 million common shares outstanding, net of 0.4 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended September 30, 2018 were 60.5 million (Q3 2017 – 59.2 million) and 59.9 million for the nine months ended September 30, 2018 (2017 – 57.6 million).

On March 14, 2017, in conjunction with the funding of the term loan, the lender received, for no additional consideration, warrants to purchase common shares of Perpetual at a ratio of 120 warrants for every $1,000 committed under the term loan, resulting in the issuance of 5.4 million warrants. Each warrant entitles the holder to acquire common shares on a one for one basis, at an exercise price equal to a $2.34 per share at any time prior to March 14, 2020. Provided the volume weighted average trading price of the common shares is greater than the exercise price for 60 consecutive calendar days (subject to certain restrictions), Perpetual will have the option to require the warrant holder to exercise all or any portion of the warrants at any time thereafter.

Further, as part of the equity private placement concurrent with the issuance of the term loan, 5.1 million common shares and 1.1 million additional warrants were issued for proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to warrants. Directors and officers of Perpetual or entities controlled by them purchased 1.6 million common shares and 0.4 million warrants for proceeds of $2.9 million as part of this private placement.

At November 7, 2018 there were 60.5 million common shares outstanding which is net of 0.4 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)	**November 7, 2018**
Share options(1)	**3.8**
Performance share rights(2)	**1.5**
Compensation awards(3)	**3.2**
Warrants(4)	**6.5**
Total	**15.0**

(1) As at September 30, 2018, all outstanding share options have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these options, the number of potentially issuable common shares would be nil.

(2) The performance share rights that vest and become redeemable are a multiple of the performance share rights granted, dependent upon the achievement of certain performance metrics over the vesting period. As at September 30, 2018, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2017 and 2018.

(3) As at September 30, 2018, 2.0 million deferred options have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these deferred options, the number of potentially issuable common shares pursuant to the compensation awards would be 1.2 million.

(4) As at September 30, 2018, all outstanding warrants have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these warrants, the number of potentially issuable common shares would be nil.

SUMMARY OF QUARTERLY RESULTS

(*$ thousands, except as noted*)	**Q3 2018**	Q2 2018	Q1 2018	Q4 2017
Financial				
Oil and natural gas revenue	**20,504**	20,774	23,340	23,810
Net loss	**(12,259)**	(1,325)	(6,465)	(6,498)
Per share – basic and diluted	**(0.20)**	(0.02)	(0.11)	(0.11)
Cash flow from (used in) operating activities	**6,729**	8,435	11,198	10,953
Adjusted funds flow[1]	**5,155**	7,847	9,101	12,541
Per share – basic	**0.09**	0.13	0.15	0.21
Net capital expenditures				
Capital expenditures	**4,343**	2,031	14,897	19,047
Net payments (proceeds) on acquisitions and dispositions	**4,341**	(7,012)	926	970
Net capital expenditures	**8,684**	(4,981)	15,823	20,017
Common shares (*thousands*)				
Weighted average – basic and diluted	**60,468**	59,876	59,345	59,338
Operating				
Daily average production				
Natural gas (*MMcf/d*)	**46.9**	53.1	65.9	60.8
Oil (*bbl/d*)	**1,022**	971	900	888
NGL (*bbl/d*)	**730**	806	848	738
Total (*boe/d*)	**9,569**	10,620	12,742	11,765
Average prices				
Realized natural gas price (*$/Mcf*)[2]	**2.83**	2.62	2.65	3.22
Realized oil price (*$/bbl*)[2]	**48.57**	53.26	48.31	47.30
NGL price (*$/bbl*)	**56.02**	60.77	57.61	54.17

(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, and realized gains and losses on financial derivatives and foreign exchange contracts.

(*$ thousands, except as noted*)	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Financial				
Oil and natural gas revenues	20,026	19,728	18,158	17,940
Net income (loss)	(8,082)	(7,219)	(14,172)	20,379
Per share – basic	(0.14)	(0.12)	(0.26)	0.39
Per share – diluted	(0.14)	(0.12)	(0.26)	0.37
Cash flow from (used in) operating activities	5,778	4,728	(2,289)	4,740
Adjusted funds flow[1]	8,199	5,265	5,110	3,329
Per share – basic	0.14	0.09	0.09	0.06
Net capital expenditures				
Capital expenditures	25,392	4,006	24,590	7,069
Net payments (proceeds) on acquisitions and dispositions	680	609	163	1,785
Net capital expenditures	26,072	4,615	24,753	8,854
Common shares (*thousands*)				
Weighted average – basic	59,152	59,045	54,468	52,924
Weighted average – diluted	59,152	59,045	54,468	54,678
Operating				
Daily average production				
Natural gas (*MMcf/d*)	51.8	45.1	40.7	40.3
Oil (*bbl/d*)	978	1,049	877	936
NGL (*bbl/d*)	733	665	479	467
Total (*boe/d*)	10,330	9,223	8,143	8,118
Average prices				
Realized natural gas price (*$/Mcf*) [2]	3.11	3.18	5.04	2.41
Realized oil price (*$/bbl*) [2]	43.01	43.91	31.39	38.95
NGL price (*$/bbl*)	39.06	44.28	49.70	46.99

(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, and realized gains and losses on financial derivatives and foreign exchange contracts.

The Company's oil and natural gas revenues, net income (loss), cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Production levels decreased through 2016 as net capital expenditures were reduced in response to low commodity prices. In the fourth quarter of 2016, production decreased due to the disposition of approximately 5,900 boe/d of production associated with the Shallow Gas Disposition. Production levels increased through 2017 as net capital expenditures were increased in response to improving commodity prices. Natural gas production levels have 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 and third quarters of 2018 at East Edson associated with the Sequoia bankruptcy. 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 acquisitions, 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 November 7, 2018:

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
October 2018	10,000	2.06	1.35	Financial
October 2018 – March 2019	10,000	1.41	2.14	Financial
October 2018 – March 2019	5,000	1.40	2.14	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for October and November 2018 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 November 7, 2018.

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

Term	Volumes sold (bought) (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)[(1)]	Market prices (*US$/MMBtu*)[(2)]	Type of contract
October 2018	5,000	(1.87)	(1.66)	Financial
October 2018	7,500	(1.80)	(1.66)	Physical
October 2018	(32,500)	(1.82)	(1.66)	Physical
November 2018 – March 2019	7,500	(1.55)	(1.55)	Physical
January 2019 – December 2019	7,500	(1.50)	(1.60)	Financial
January 2019 – December 2019	12,500	(1.54)	(1.60)	Physical
April 2019 – October 2019	5,000	(1.62)	(1.75)	Physical
April 2019 – October 2019	(10,000)	(1.64)	(1.75)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.39)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.39)	Physical
January 2021 – December 2021	5,000	(1.15)	(1.16)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for October and November 2018 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 November 7, 2018.

Crude Oil

The following table provides a summary of fixed price oil contracts which settle in US$:

Term	Volumes (*bbl/d*)	Fixed price (*US$/bbl*)[(1)]	Market prices (*US$/bbl*)[(2)]	Type of contract
October 2018 – December 2018	250	63.74	64.80	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for October are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on November 7, 2018.

The Company had entered into financial 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
October 2018 – December 2018	250	50.00	58.40	64.80	Financial
October 2018 – December 2018	250	50.00	60.00	64.80	Financial
January 2019 – December 2019	500	60.00	72.40	63.00	Financial

(1) Market prices for October are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on November 7, 2018.

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

Term	Volumes (*bbl/d*)	WTI-WCS differential (*US$/bbl*)[(1)]	Market prices (*US$/bbl*)[(2)]	Type of contract
January 2019 – December 2019	500	(26.85)	(27.90)	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 October 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 November 7, 2018.

Foreign Exchange

The Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated oil and NGL commodity sales:

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Market prices (*US$/Cdn$*)
October 2018	1,500,000	1.30	1.30

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$/month*)	Strike rate (*US$/Cdn$*)	Market prices (*US$/Cdn$*)
October 2018	2,000,000	1.30	1.30
November 2018 – March 2019	2,500,000	1.30	1.31
April 2019 – October 2019	2,000,000	1.31	1.31
November 2019 – March 2020	2,000,000	1.29	1.30
April 2020 – October 2020	1,500,000	1.30	1.30

Natural Gas Sales Obligations

Natural gas volumes sold pursuant to the Company's five-year market diversification contract which expires October 31, 2022, include a fixed volume obligation of 35,000 MMBtu/d (40,000 MMBtu/d commencing April 1, 2018) 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 follows:

Market/Pricing Point	Daily sales volume (*MMBtu/d*)
Chicago	12,200
Malin	10,800
Dawn	8,000
Michcon	5,200
Empress	3,800
Total natural gas sales volume obligation	**40,000**

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

ACCOUNTING PRONOUNCEMENTS

Recently adopted

IFRS 9 "Financial Instruments"
On January 1, 2018, Perpetual adopted IFRS 9 "Financial Instruments" as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Perpetual's condensed interim consolidated financial statements.

IFRS 15 "Revenue from Contracts with Customers"
On January 1, 2018, Perpetual adopted IFRS 15 "Revenue from Contracts with Customers". IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Perpetual's revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices.

Perpetual adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

Issued but not yet adopted

IFRS 16 "Leases"
Perpetual is required to adopt IFRS 16 "Leases" by January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. On adoption, non-current assets, current liabilities and non-current liabilities on the Company's statement of financial position will increase. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation. This is expected to result in a decrease to operating expense and general and administrative expense and an increase to interest expense and adjusted funds flow. The Company will disclose additional information on the progress of the transition when it reports its fourth quarter 2018 results, and has yet to quantify the impacts of this standard.

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 January 1, 2018 and ended September 30, 2018 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, NGLs 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; 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 2018 and 2019; 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.