# 2017 ANNUAL RESULTS

PERPETUAL
ENERGY

# TO SHAREHOLDERS

2017 was a year of continued transformation with a return to stability for Perpetual. We successfully advanced critical steps to position the Company to continue to navigate the current volatile, and in some aspects hostile, business environment. The asset base high-grading strategy we executed in the fourth quarter of 2016 with the disposition of the majority of our high liability, high cost legacy mature shallow gas properties in east central and northeast Alberta, positioned us well to restore corporate profitability in 2017.

This strategic focusing of our asset base, along with continued diligence to drive down costs, strengthening of our balance sheet, and steady execution of our growth-oriented capital program, delivered positive results in 2017.

A series of financing transactions in 2017 established financial flexibility to fund our growth-oriented business plan. We repaid senior notes which were due to mature in 2018, a year in advance of their maturity date, and extended the term of a portion of the remaining senior notes to 2022, leaving just $14.6 million with a maturity date in July 2019. We secured a $45 million four year term loan and raised gross proceeds of $9 million through a private placement of common shares and warrants. Improved operational performance also led to three borrowing base increases to the Company's reserve based credit facility and the syndicate was expanded to include two additional banks. Approximately 59% of our net debt now has repayment terms into 2021 or beyond. During 2017, the Company's credit rating was increased by both Moody's and Standard & Poors, based on Perpetual's improved liquidity.

During 2017, we shifted our focus to profitable capital investment to drive both production and adjusted funds flow growth. At the same time, we maintained our vigilance to further reduce costs in all aspects of our operations. Exploration and development capital investment of $73 million in 2017 was 90% focused on liquids-rich natural gas development in East Edson. Year-over-year exit rate growth of 54% was attained (average production for the month of December) and proved and probable reserves were added to replace 248% of annual production. Perpetual established over 11.3 MMboe of new proved developed producing ("PDP") reserves at a finding and development cost of $6.44/boe, resulting in a 2.2 times PDP recycle ratio relative to operating netback and 1.3 times relative to adjusted funds flow of $8.64/boe. This PDP recycle ratio is highly attractive amongst our Western Canadian competitors.

Operating netbacks of $14.35/boe in 2017 were 120% higher than in 2016, driven by the establishment of a sustainable cost structure following the strategic shallow gas property disposition coupled with proactive natural gas price hedging, price optimization tactics and market diversification strategies. Total production and operating expenses continued on a downward trend through the year, decreasing 53% to average $4.52/boe in 2017 and $3.45/boe in Q4 2017, reflecting company-wide cost saving initiatives, concentration of operations to the low-cost East Edson area and the full year impact in 2017 of the sale of the high cost legacy shallow gas properties.

These strategic activities proved out in our financial results. Adjusted funds flow for 2017 grew thirty-fold to $31.1 million ($0.54/share) compared to $0.9 million ($0.02/share) in 2016. Year-end 2017 net debt to fourth quarter 2017 annualized adjusted funds flow ratio was 2.1 times.

As the Company moves into 2018, we are positioned with a diversified foundation of resource-style plays which include liquids-rich gas, heavy oil, shallow shale gas and longer-term bitumen opportunities that in aggregate provide a solid platform to grow value for our shareholders.

Perpetual's top four strategic priorities for 2018 continue to be:

- Grow the value of Greater Edson liquids-rich gas;
- Grow the value of the Eastern Alberta portfolio;
- Advance high impact opportunities; and
- Optimize the balance sheet for growth.

In response to recent commodity market changes, Perpetual has set a 2018 capital plan designed to prudently defer development of the Company's East Edson natural gas asset to ensure maximum returns from development of the reserves and re-allocate capital to heavy oil prospects in its diversified portfolio of opportunities, accelerating spending on highly economic heavy oil projects at Mannville. The revised capital spending plan is expected to result in 2018 adjusted funds flow in excess of capital expenditures and obligations, allowing for debt repayment and other opportunities.

We remain on a path to grow value for all shareholders. Through creativity, flexibility and our entrepreneurial spirit, we are set to pursue new opportunities and capture the inherent value of our diversified portfolio of resource-style plays for the short, medium and long term. The Board of Directors and Management remain grateful for the talent and deep commitment of our team and the support of our shareholders.

Susan Riddell Rose

**SUE RIDDELL ROSE**
President and Chief Executive Officer

February 23, 2018

# 2017 ANNUAL HIGHLIGHTS

## 2017 FINANCIAL AND OPERATING HIGHLIGHTS

### Capital Spending, Production and Operations

- Perpetual's exploration and development spending in 2017 totaled $73.0 million, a five-fold increase over 2016 capital spending, adding proved plus probable reserves of 8.9 MMboe, equivalent to 248% of 2017 production, at a finding and development ("F&D") cost of $6.16/boe. Approximately 90% of spending was concentrated on the West Central Alberta deep basin assets. Capital expenditures included drilling 19 wells (17.7 net), with 13 (13.0 net) liquids-rich wells at East Edson, one (0.4 net) well in the Brazeau area of West Central Alberta and four (3.3 net) horizontal heavy oil wells and one (1.0 net) shallow horizontal gas well at Mannville. Capital activity in 2017 also included $2.1 million to expand the processing capacity at the owned and operated West Wolf Lake gas plant in East Edson and heavy oil waterflood activities and a shallow gas recompletion program at Mannville. In addition, modest spending was committed to complete phase one of the Company's strategic low pressure electro-thermally assisted drive ("LEAD") pilot project with cyclic heat stimulation ("CHS") testing of the bitumen extraction opportunity in the Bluesky formation at Panny.

- Net payments on dispositions were $2.0 million in 2017 and included $2.9 million in net payments associated with the retained marketing arrangements related to the sale of mature shallow gas properties in east central and northeast Alberta in the fourth quarter of 2016 (the "Shallow Gas Properties"), offset by $0.9 million in net proceeds on the sale of undeveloped land and seismic data.

- Perpetual spent $2.3 million on decommissioning expenditures during 2017 mainly in Eastern Alberta, down from $3.8 million in 2016 as a result of materially reduced obligations with the disposition of the Shallow Gas Properties.

- Total proved plus probable reserves grew by 9% to 66.6 MMboe, as reported by the independent engineering firm McDaniel and Associates Consultants Ltd. ("McDaniel"), up 5.3 MMboe after 2017 production of 3.6 MMboe. Importantly, the Company grew total proved reserves by 22% to 42.8 MMboe (64% of total proved plus probable reserves) and doubled its proved developed producing reserves to 15.9 MMboe. Proved plus probable developed producing reserves were 20.5 MMboe at December 31, 2017, 44% higher than year-end 2016.

- The net present value ("NPV") of Perpetual's total proved plus probable reserves (discounted at 10%) before income tax, grew by 8% to $409.9 million (2016 – $380.7 million), despite a decrease in McDaniel's forecast for both oil and natural gas prices at year-end 2017.

- Based on McDaniel's commodity price forecasts, Perpetual's reserve-based net asset value ("NAV") (discounted at 10%) at year-end 2017 is estimated at $336.5 million ($5.68/share).

- Total production for the year ended December 31, 2017 of 9,876 boe/d was 30% lower than 2016 (14,128 boe/d), reflecting the sale of close to 35.5 MMcf/d (5,900 boe/d) of natural gas with the Shallow Gas Property disposition. Perpetual's natural gas production averaged 49.6 MMcf/d in 2017, 87% concentrated at East Edson. NGL production averaged 655 bbl/d (62% condensate), 7% higher than 614 bbl/d (66% condensate) in 2016. Oil production of 948 bbl/d for 2017 was 10% lower than 2016 (1,058 bbl/d).

- Total production and operating expenses decreased 53% to $16.3 million ($4.52/boe) for 2017 compared to $35.0 million ($6.77/boe) in 2016, reflecting company-wide cost saving initiatives, concentration of operations to the low-cost East Edson area and the full year impact in 2017 of the sale of the high cost Shallow Gas Properties. Operating costs in West Central Alberta averaged $2.68/boe for 2017 compared to $2.93/boe in 2016.

- Municipal property taxes of $2.2 million continued to represent a significant portion of fixed operating costs at $0.62/boe (14% of total operating costs) for the year ended December 31, 2017, particularly in the Company's remaining Eastern Alberta properties.

### Financial Highlights

- Realized revenue of $85.0 million in 2017 was 1% lower than 2016 as the 30% decrease in production was offset by a similar increase in Perpetual's average realized commodity prices, inclusive of the Company's hedging, price optimization and market diversification strategies. Realized revenue per boe was $23.59/boe for 2017, up 42% over the prior year (2016 – $16.65/boe), driven by modestly improved benchmark commodity prices combined with the higher value production sales mix and effective natural gas price optimization strategies.

- AECO Daily Index prices were essentially flat year over year at $2.04/GJ. Perpetual's average realized gas price, including derivatives, and adjusted for heat content increased 45% to $3.51/Mcf for the year ended December 31, 2017 from $2.42/Mcf in 2016. Perpetual's average realized natural gas price in 2017 was 163% of the AECO Daily Index price as a result of positive hedging gains, prompt month price optimization strategies, and the commencement of the Company's market diversification contracts in the fourth quarter as well as the higher heat content of the natural gas sales stream in the East Edson area.

- Perpetual's realized oil price of $41.62/bbl, including derivatives, increased 11% compared to 2016, due primarily to the 29% increase in Western Canadian Select ("WCS") pricing. The increase in the average WCS price was primarily driven by higher benchmark WTI prices and lower WCS differentials compared to the prior year. Also included in Perpetual's realized oil price were realized losses of $0.8 million ($2.31/bbl) recorded on financial crude oil derivative contracts for the WCS differential and $0.9 million ($2.60/bbl) of losses realized on crystallizations of contracts before maturity.

- Perpetual's realized average NGL price increased 31% from the prior year to $46.60/bbl, reflecting an increase in all NGL component prices due to an increase in year-over-year pricing for WTI. As well, propane prices increased due to US inventory levels for propane ending the year at the lowest level since 2013 due to increased exports from the United States to Asia and Europe.

- Royalty expenses for 2017 were $12.0 million ($3.32/boe), up from $9.4 million ($1.82/boe) in 2016 and representing a 26% increase in the effective combined average royalty rate on P&NG revenue to 14.6% from 11.6% in 2016. Average crown royalty rates increased to 2.5% in 2017 compared to 2.1% in 2016, due primarily to higher Alberta natural gas reference prices and increasing oil prices. Freehold and overriding royalty rates increased from 9.5% in 2016 to 12.1% in 2017 as the East Edson joint venture royalty represented a higher percentage of production and revenue following the Shallow Gas Property sale and other production additions in 2017 were subject to overriding royalties.

- Operating netbacks of $14.35/boe in 2017 were 120% higher than in 2016 ($6.53/boe), driven by higher realized revenue combined with lower production and operating expenses and transportation costs, offset by higher royalties.

- Cash interest expense in 2017 decreased 46% to $8.0 million (2016 – $14.7 million) due to the full year effect of the exchange during the second quarter of 2016 of $214.4 million principal amount of 8.75% senior notes for 4.4 million TOU shares owned by Perpetual and asset sales in 2016 contributing to a lower opening debt balance, partially offset by capital expenditures that exceeded adjusted funds flow through 2017.

- Cash Costs were $53.3 million in 2017, 37% ($30.9 million) lower than 2016. On a unit-of-production basis, Cash Costs of $14.77/boe in 2017 were 10% lower ($1.56/boe) relative to 2016.

- Cash flow from operating activities was $19.2 million ($0.33/share), compared to negative $7.1 million ($0.14/share) in 2016. Year-over-year improvements in commodity prices combined with significant cost reductions in 2017 more than offset the impact of the 30% decline in average daily production from 2016 to 2017.

- Adjusted funds flow was $31.1 million or $0.54/share, compared to $0.9 million or $0.02/share in 2016 driven by the establishment of a sustainable cost structure with the strategic disposition of the Shallow Gas Properties.

- Perpetual recorded a net loss of $36.0 million ($0.62/share) in 2017, compared to net income of $107.1 million ($2.11/share) for 2016. Change in net income was primarily due to the absence of the 2016 $81.3 million gain on exchange of senior notes for shares of Tourmaline Oil Corp. ("TOU"), the $81.6 million year-over-year decrease in the change in fair value of TOU share investment and the $36.5 million year-over-year decrease in gains on dispositions. Income (loss) from operating activities in 2017, before impairment losses (reversals), restructuring expense and loss (gain) on dispositions was $3.7 million compared to ($32.1 million) in 2016, representing a $35.8 million improvement due to higher realized commodity prices and cost reductions in 2017, and the sale of the Shallow Gas Properties in 2016.

- The Company's balance sheet was strengthened during 2017 through the execution of a series of financing transactions. The repayment term of $17.9 million of senior notes that previously were scheduled to mature in 2018 and 2019 was extended to 2022 and $27.1 million of senior notes that were scheduled to mature in 2018 were redeemed. Further, the Company issued a $45 million term loan due in 2021 and raised gross proceeds of $9.0 million through the private placement of 5.1 million common shares and 6.5 million warrants.

- Total net debt at December 31, 2017 was $106.0 million. Approximately $62.9 million, representing 59% of net debt, matures in 2021 or later. Revolving bank debt stood at $31.6 million at year-end 2017. Three borrowing base increases to the Company's reserve based revolving bank debt during 2017 increased total borrowing capacity to $65 million. The maturity date of the revolving bank debt is May 31, 2019 and the next semi-annual borrowing base review is scheduled for May 31, 2018. On November 20, 2017, S&P upgraded Perpetual's credit rating by two rating notches from CCC- to CCC+ with a stable outlook, based on Perpetual's improved liquidity. The Company's year-end 2017 net debt to fourth quarter 2017 annualized adjusted funds flow ratio was 2.1 times.

## 2017 STRATEGIC PRIORITIES

**Perpetual's top four strategic priorities for 2017 included:**

1. Grow the value of Greater Edson liquids-rich gas;
2. Optimize the value potential of Eastern Alberta assets;
3. Advance high impact opportunities; and
4. Optimize the balance sheet for growth.

Significant progress was made to advance the Company's strategic priorities as outlined below.

### *Grow the value of Greater Edson liquids-rich gas*

- Spending on East Edson liquids-rich gas projects for 2017 totaled $63 million and included the drilling of 13 (13.0 net) horizontal natural gas wells, two of which were extended reach horizontal ("ERH") wells.

- Eleven (11.0 net) of the wells drilled in 2017 had an average 1,700 meters horizontal length and pioneered a new monobore well design. This new design, coupled with lower service costs, reduced the total cost of a typical Edson well to $4.2 million (inclusive of drilling, completion, equipment and tie-in), driving capital efficiencies from an average $11,000 per boe/d during 2014 to 2016 to $8,600 per boe/d based on first 12-month average production as per McDaniel's proved developed producing forecast, despite operational difficulties on one well which had a significantly higher capital efficiency ratio.

- The two (2.0 net) ERH wells drilled in the second half of 2017 were designed to evaluate the cost/benefit analysis of ERH wells for future development of the Wilrich reserves and were successfully drilled to 2,460 meters and 3,489 meters in length, with the third ERH well rig released in the first quarter of 2018 at 2,953 meters. Preliminary results suggest that capital efficiencies will be further reduced through this development approach.

- The first ERH well at 4-23-51-16W5 represented the highest deliverability well drilled to date by Perpetual at East Edson with a thirty-day average initial productivity ("IP30") of 15.6 MMcf/d of natural gas plus associated liquids based on field estimates, 75% higher than the length-adjusted type curve contained in the 2017 year-end McDaniel reserve report. The second ERH well is below the length-adjusted type curve for gas, but has a higher liquid yield. The sum of the two wells is anticipated to exceed McDaniel's proven plus probable expectations.

- Compression was added at the 100% owned and operated West Wolf Lake 10-3 plant, to align compression and process capacity at the facility, bringing the plant capacity to 65 MMcf/d, and area capacity to 78 MMcf/d, including the 15% working interest capacity held at a third-party operated facility in Rosevear. The facility expansion was completed in December 2017 for $2.1 million, on budget and three months ahead of schedule, to accommodate the accelerated availability of increased firm transportation on TCPL to 78 MMcf/d from April 1, 2018 to December 17, 2017.

- Production at East Edson comprised 80% of total Company production in 2017 and increased 6% relative to 2016 to average 7,896 boe/d. The production growth was driven by the drilling program despite production constraints caused by firm transportation capacity and voluntary shut-ins averaging 245 boe/d for the year as part of Perpetual's price optimization strategy. The 2017 exit rate of 10,545 boe/d based on average production for the month of December was 64% higher year-over-year.

- During the second half of 2017, industry transportation maintenance activities restricted available capacity and temporarily depressed natural gas prices at AECO. In response, Perpetual voluntarily shut-in an average 450 boe/d of production at East Edson during the third quarter and 500 boe/d in the fourth quarter (2017 annual average – 245 boe/d) to preserve value and take advantage of temporary situations when natural gas could be purchased at nominal cost and delivered against pre-sold volume commitments at attractive margins.

- East Edson represented 92% (2016 – 93%) of total proved plus probable reserves at year-end 2017. Reserve additions associated with the 13 well drilling program more than compensated for production of close to 2.9 MMboe, increasing proved plus probable producing reserves by 49%. A revised future development plan including the new ERH well design and higher production capacity, resulted in an overall reduction of future development capital while growing total proved plus probable reserves by 8%.

- Perpetual's low operating cost structure at East Edson further improved to average $2.68/boe in 2017 (2016 – $2.93/boe). Production and operating expenses decreased by 9% on a per boe basis compared to the prior year due to lower maintenance and repair costs, purchased energy costs, and processing fees combined with the impact of increased production on a substantially fixed operating cost base.

- The Company continues to monitor production from a competitor's lower Mannville Ellerslie horizontal well drilled in late 2016 to inform the economic viability of this liquids-rich natural gas zone as a secondary development target at East Edson. Perpetual has 52.8 gross (42.6 net) sections at East Edson in the prospective play fairway. Reported condensate rates from the competitor well have remained relatively steady, averaging 62 bbl/d (59 bbl/MMcf) since inception of production.

- The rig release of the third ERH well in the first quarter of 2018 finished the continuous East Edson single-rig drilling program that began after break-up in 2017. Completion operations for this third ERH well, originally scheduled for the first quarter of 2018, have been deferred to the fourth quarter of 2018, anticipating stronger future natural gas prices to maximize profitability. Assuming continued weakness in AECO natural gas prices, the four-well East Edson drilling program initially planned for the third quarter of 2018 will be deferred pending stronger AECO natural gas prices.

*Optimize the value potential of Eastern Alberta assets*

- Capital spending in Eastern Alberta amounted to $7.8 million during 2017, drilling one (1.0 net) exploratory natural gas well and four (3.3 net) heavy oil wells, three of which were exploratory. Drilling activities in 2017 resulted in production from one new Sparky heavy oil pool, and increased production in the I2I pool which has been under waterflood since late 2013. The remaining activity was primarily directed towards waterflood optimization with the conversion of one new injector, one new disposal well and pipeline construction for water management. The 2017 capital program also included expenditures for high return conventional shallow gas workovers and recompletions.

- Crude oil production in eastern Alberta declined 11% year-over-year to 929 bbl/d, reflecting natural declines offset by only modest capital investment activity. Positive waterflood response is being observed in several heavy oil pools where producing gas-oil ratios are declining and oil production decline rates have stabilized and in some cases oil production is increasing with pressure support. This successful waterflood performance, combined with continued capital investment, is expected to result in higher recovery of oil in place, as evidenced by the 16% increase in total proved plus probable reserve in the Mannville heavy oil area reported by McDaniel at year-end 2017.

- Gas production in eastern Alberta was effectively flat at 6.3 MMcf/d relative to the fourth quarter of 2016 as recompletion and workover activities on 13 wells offset natural declines. Low variable operating costs in Mannville result in recompletions paying out within six months even at low commodity prices.

- Total proved plus probable reserves were 3.3 MMboe at December 31, 2017, up 0.5 MMboe from year-end 2016. While Mannville heavy oil reserves account for just 5% of Perpetual's total proved plus probable reserves, this core area accounts for 9% of Perpetual's total proved developed producing reserves and 10% of total proved plus probable developed producing reserves.

- Perpetual spent $1.4 million on abandonment and reclamation projects in eastern Alberta during 2017, executing an internally-managed asset-retirement program, including well abandonments, pipeline discontinuations and abandonments, as well as reclamation work to reduce mineral and surface lease rental payments, maintenance costs and high municipal taxes associated with the linear property in the Mannville area. Perpetual received 35 reclamation certificates which enable reduced property tax and surface lease rental costs going forward.

- Production and operating expenses in eastern Alberta were $11.88/boe in 2017 (2016 – $11.06/boe). The Company continues to prioritize cost reductions on its eastern Alberta assets, including a focus on municipal property taxes which represent a significant portion of fixed operating costs as the tax base assessment is dramatically misrepresentative of the actual tangible property value.

- Municipal property taxes of $1.6 million in eastern Alberta continued to represent a significant portion of fixed area operating costs at $2.23/boe (17% of total operating costs) for the year ended December 31, 2017. The calculation of property taxes for machinery and equipment, pipelines and wells is based on a prescribed formula methodology which results in a tax assessment base that is dramatically misrepresentative of the property value for the Company's remaining mature shallow gas assets. As a result, property taxes for the Company's mature shallow gas assets in Eastern Alberta for 2017 were $1.0 million ($2.84/boe), which represented 46% of operating costs for the shallow gas production and 51% of the pre-municipal tax operating netback for these properties.

- In the first quarter of 2018, construction of additional water handling and disposal facilities are underway and the first of an up to four (4.0 net) well (10 multi-lateral legs) drilling program to develop the Birch General Petroleum A pool in Mannville was spud on January 31, 2018.

- Three (2.3 net) development wells are expected to proceed as planned in the third quarter of 2018, along with up to six (6.0 net) additional wells at Mannville to evaluate the future horizontal development potential of three undeveloped heavy oil pools.

*Advance high impact opportunities*

- Two horizontal pilot wells were drilled during the fourth quarter of 2016 and the first quarter of 2017 to advance the evaluation of the shallow shale gas play in the Viking and Colorado formations in eastern Alberta. The two wells are on production at low rates and continue to be evaluated to inform future drilling and completion program designs and reservoir performance potential. Fracture stimulation of the Viking gas well has not been fully executed to date and additional spending has been delayed pending further learnings from performance monitoring and stronger natural gas prices. The Company remains encouraged by the potential of horizontal development of the tight Viking formation but has reverted to an incremental spending model to technically advance the play through recompletion activities during this current period of depressed natural gas prices in Alberta.

- Perpetual turned down its cyclic heat stimulation test at Panny during the second quarter of 2017 after its fourth cycle of production. The CHS test provided high quality data and yielded valuable insights regarding reservoir performance, the functionality of the electrical heating cable, preliminary solvent opportunities and other operational considerations to advance the pilot project targeting bitumen recovery from the Bluesky formation. Perpetual is currently evaluating the application of solvent technology with heat, utilizing important learnings from the CHS project. Solvent technology has the potential to augment production rates and recovery and increase capital and operating efficiencies as well as positively enhance environmental performance through reduced emissions and water usage. These learnings will be integrated into a plan for next steps to advance the assessment of the commercial development potential of this large scope Bluesky resource.

- In the Columbia/Brazeau area of West Central Alberta, Perpetual's lands are prospective in multiple horizons including Cardium, upper Mannville and Spirit River zones. Perpetual participated for its 40% working interest in a third-party operated exploratory horizontal well targeting the Fahler formation. The well was rig released at the end of the third quarter and placed on production at lower than anticipated rates and is producing intermittently.

- In early 2014, Perpetual entered into a farm-out agreement on 6,240 acres of Duvernay rights in the Waskahigan area. The farmee drilled a horizontal well into the Duvernay which was completed during the fourth quarter of 2014. After significant delays substantially due to transportation restrictions in the area, continuous production from this well was started in late 2015. During the well's first two months of free flowing production, it produced an average of 250 bbl/d condensate and 270 Mcf/d of natural gas (net 100 boe/d). With the earn-in terms fulfilled, Perpetual retains a 35 percent working interest in 3,840 gross acres and 100 percent working interest in the remaining 2,400 acres. The well was produced intermittently in 2018 as a result of area infrastructure disruptions. Continued Duvernay formation investment by competitors has resulted in significant changes to well and completion design, capital costs and well performance. Nearby offsets to Perpetual's land have been drilled by competitors in early 2018 which will provide valuable information to assess future development potential and economic viability.

*Optimize the balance sheet for growth*

- In January 2017, $17.4 million aggregate principal amount of existing senior notes maturing in 2018 and 2019 were exchanged for new 8.75% senior notes having an extended maturity date of January 23, 2022 (the "2022 Senior Notes").

- During the first quarter of 2017, 180,000 TOU shares were sold at $31.63 per TOU share for net cash proceeds of $5.7 million. At December 31, 2017, the balance of TOU shares held by the Company was 1.67 million with a market value of $38.0 million ($22.78/share).

- On March 14, 2017, a $45 million senior secured term loan facility (the "Term Loan") with Alberta Investment Management Corporation ("AIMCo.") was closed, bearing annual interest at 8.1% and maturing in March 2021. The initial draw on the Term Loan was $35 million with the remaining $10 million drawn on October 5, 2017. In addition, for no additional consideration, 5.4 million warrants were issued which entitle AIMCo. to acquire common shares on a one for one basis for a period of up to three years, at an exercise price of $2.34/share.

- Concurrent with the establishment of the Term Loan, Perpetual issued equity units consisting of 5.1 million common shares and 1.1 million additional warrants at $1.75 per equity unit for aggregate gross proceeds of $9 million.

- On April 17, 2017, Perpetual exchanged $0.5 million 2018 Senior Notes for new 2022 Senior Notes and completed the early cash repayment of the remaining $27.1 million 2018 Senior Notes.

- On July 31, 2017, Perpetual entered into a new $18.7 million margin loan secured by 1.67 million TOU shares that matures in July 2018. Proceeds from the new margin loan along with borrowings under the Credit Facility were used to repay the TOU share put option margin loans that were scheduled to mature in August and November of 2017. Proceeds of $1.0 million were realized from the sale of underlying put options.

- In mid-July, $1.0 million of 2019 Senior Notes were purchased at 96.75% of face value and retired. This reduction, in addition to the other senior note transactions executed during the first half of 2017, contributed to a 46% decrease in senior note principal balance outstanding from year-end 2016 with the next maturity due in July 2019.

- In light of the positive financing transactions, in early July, Moody's Investor Service upgraded Perpetual's corporate credit rating to Caa1 stable.

- In order to protect a base level of adjusted funds flow, Perpetual had commodity price contracts in place during 2017 which resulted in realized gains on derivatives of $3.3 million, comprised of $9.2 million of gains on natural gas hedges, partially offset by $1.7 million of losses from oil hedges and $4.2 million of losses on foreign exchange hedges.

- Realized gains on prompt month natural gas price optimization operations added $0.28/Mcf ($5.1 million) in 2017 and included $0.06/Mcf ($1.0 million) associated with the purchase of third party gas at nominal cost to deliver against pre-sold volume commitments.

- Perpetual diversified its natural gas price exposure from AECO by entering into arrangements to shift the sales point of 34.1 MMcf/d to a basket of five North American natural gas hub pricing points (Chicago, Dawn, Empress, Malin and Mich Con) for a five year period commencing November 1, 2017 (39.0 MMcf/d commencing April 1, 2018). Based on current futures prices, Perpetual expects these gas price diversification contracts will provide a significant premium over AECO prices for the November 2017 to December 2018 time frame. During the fourth quarter of 2017, these contracts contributed a $0.19/Mcf increase in Perpetual's average realized natural gas price ($1.0 million incremental revenue) compared to the AECO Daily Index in the fourth quarter.

- Three borrowing base increases to the Company's reserve based Credit Facility during 2017 grew total borrowing capacity to $65 million. The maturity date of the revolving bank debt is May 31, 2019 and the next semi-annual borrowing base review is scheduled for May 31, 2018.

- On November 20, 2017, S&P upgraded Perpetual's credit rating by two rating notches from CCC- to CCC+ with a stable outlook, based on Perpetual's improved liquidity.

- Adjusted funds flow was $31.1 million or $0.54/share in 2017, compared to $0.9 million or $0.02/share in 2016, driven by the establishment of a sustainable cost structure, despite lower year-over-year production related to the strategic disposition of the Shallow Gas Properties in the fourth quarter of 2016 and flat AECO Daily Index prices. Adjusted funds flow of $12.5 million ($0.21/share) in the fourth quarter of 2017 was up 277% (250% on a per share basis) over the comparative period in 2016 and 53% over the third quarter of 2017.

- Total net debt at December 31, 2017 was $106.0 million. Approximately $62.9 million, representing 59% of net debt, matures in 2021 or later. Revolving bank debt stood at $31.6 million at year-end 2017.

- Through the series of financing transactions and operational performance, liquidity improved materially year-over-year. At year-end 2017, Perpetual has undrawn capacity of approximately $33.4 million under the Credit Facility. Combined with the year-end market value of the Company's TOU share investment, net of the margin loan and other letters of credit posted for operational purposes, total available liquidity at year-end 2017 stood at $45 million.

- The Company's year-end 2017 net debt to fourth quarter 2017 annualized adjusted funds flow ratio was 2.1 times.

## 2017 RESERVE HIGHLIGHTS

- Total proved plus probable reserves were 66.6 MMboe at December 31, 2017, up 5.3 MMboe (9%) from year-end 2016 after production of 3.6 MMboe.
- Total proved producing reserves were 15.9 MMboe at December 31, 2017, up 99% from year-end 2016 and proved plus probable producing reserves were 20.5 MMboe at December 31, 2017, up 44% from year-end 2016.
- On a commodity basis, oil and natural gas liquids ("NGL") represent 12% (11% at year-end 2016) of Perpetual's total proved plus probable reserves and 11% (11% at year-end 2016) of total proved reserves at December 31, 2017.
- Positive technical proved reserve revisions in both East Edson and Mannville heavy oil assets offset total Company annual production of 3.6 MMboe by 284%, highlighting strong operational performance and drilling results from the Company's core assets.
- Despite a decrease in McDaniel's forecast for both oil and natural gas prices, the NPV (discounted at 10%) ("NPV10") of the proved plus probable reserves increased by 8% at year-end 2017 to $409.9 million, highlighting the value growth created through demonstrated material operating cost reductions and enhanced capital efficiencies. The increase in value of the proved plus probable reserves was driven by strong well performance at both East Edson and Mannville and a 5% reduction to forecast future development capital ("FDC").
- Perpetual's NAV (discounted at 10%) at year-end 2017 was preserved at $336.5 million ($5.68/share) as compared to $394.8 million ($7.33/share) at year-end 2016, despite lower forecast commodity prices. See the detailed NAV calculation under the heading *"NET ASSET VALUE"*.

**Reserves Summary**

Working interest reserves included herein refer to working interest reserves before royalty deductions. Reserves information is based on an independent reserves evaluation report prepared by McDaniel's with an effective date of December 31, 2017 (the "McDaniel Report"), and has been prepared in accordance with National Instrument 51-101 ("NI 51-101") using McDaniel's forecast prices and costs. Complete NI 51-101 reserves disclosure including after-tax reserve values, reserves by major property and abandonment costs has been included in Perpetual's Annual Information Form ("AIF"), and is available on the Corporation's website at www.perpetualenergyinc.com and SEDAR at www.sedar.com. Perpetual's reserves at December 31, 2017 are summarized below:

**Working Interest Reserves at December 31, 2017**[1]

| | Light and Medium Crude Oil (*Mbbl*) | Heavy Oil (*Mbbl*) | Conventional Natural Gas (*MMcf*) | Natural Gas Liquids (*Mbbl*) | Oil Equivalent (*Mboe*) |
|---|---|---|---|---|---|
| Proved Producing | 72 | 1,371 | 80,681 | 997 | 15,887 |
| Proved Non-Producing | – | 196 | 10,103 | 151 | 2,030 |
| Proved Undeveloped | – | 438 | 136,937 | 1,614 | 24,875 |
| **Total Proved** | 72 | 2,004 | 227,721 | 2,761 | 42,791 |
| Probable Producing | 11 | 445 | 22,995 | 295 | 4,583 |
| Probable Non-Producing | – | 73 | 4,568 | 34 | 868 |
| Probable Undeveloped | – | 472 | 97,845 | 1,577 | 18,357 |
| **Total Probable** | 11 | 990 | 125,408 | 1,906 | 23,808 |
| **Total Proved plus Probable** | 83 | 2,994 | 353,129 | 4,667 | 66,599 |

(1) May not add due to rounding.

**Future Development Capital**[1]

| (*$ millions*) | **2018** | **2019** | **2020** | **2021** | **2022** | **Remainder** | **Total** |
|---|---|---|---|---|---|---|---|
| Eastern Alberta Shallow Gas | 1.0 | 0.2 | – | – | – | – | 1.2 |
| Mannville Heavy Oil | 6.6 | 3.3 | – | – | – | – | 9.9 |
| East Edson Wilrich | 32.8 | 41.6 | 39.4 | 40.1 | 41.3 | 142.1 | 337.3 |
| **Total** | **40.4** | **45.1** | **39.4** | **40.1** | **41.3** | **142.1** | **348.4** |

(1) May not add due to rounding.

McDaniel's estimates the FDC required to convert proved plus probable non-producing and undeveloped reserves to proved producing reserves, to be $348.4 million at December 31, 2017. Estimated FDC decreased by $19.2 million, down from $367.6 at year-end 2016, and $458.7 million at year-end 2015. On a proved plus probable basis, FDC decreased by $23.4 million related to the future development of reserves at East Edson and increased $4.2 million in the Mannville heavy oil area. Positive adjustments were related to improvements in capital efficiencies in East Edson due to changes in well design. ERH wells (2,000 – 3,500 meters in horizontal length) are modeled at higher total cost, but have improved capital efficiencies as higher production more than makes up for costs on a per meter basis. The increased reservoir coverage and higher per well rates due to the ERH wells utilized in the future development plan in the Wilrich formation at East Edson has reduced the total number of locations in the total proved plus probable eight year development plan to 63.3 net undeveloped locations (2016 – 72.7 net locations). The projects are forecast by McDaniel's to generate annual operating cash flow in excess of the annual FDC, making the projects self-funding.

## NET PRESENT VALUE OF RESERVES SUMMARY

Perpetual's oil, natural gas and NGL reserves were evaluated by McDaniel's using McDaniel's product price forecasts effective January 1, 2018 prior to provision for financial oil and natural gas price hedges, income taxes, interest, debt service charges and general and administrative expenses. The following table summarizes the NPV of funds flows from recognized reserves at January 1, 2018, assuming various discount rates:

**NPV of Reserves, before income tax(1)(2)**

| (*$ millions except as noted*) | **Undiscounted** | **5%** | **8%** | **10%** | **15%** | **Discounted at 20%** | **Unit Value Discounted at 10%/Year (*$/boe*)(3)** |
|---|---|---|---|---|---|---|---|
| Proved Producing | 155.7 | 141.9 | 133.7 | 128.7 | 117.4 | 108.1 | 12.61 |
| Proved Non-Producing | 31.3 | 21.8 | 18.2 | 16.3 | 12.8 | 10.3 | 9.14 |
| Proved Undeveloped | 288.3 | 185.4 | 145.2 | 124.3 | 86.0 | 60.8 | 5.64 |
| **Total Proved** | **475.2** | **349.1** | **297.1** | **269.2** | **216.2** | **179.2** | **7.91** |
| Probable Producing | 80.1 | 53.4 | 43.3 | 38.1 | 29.0 | 23.1 | 10.22 |
| Probable Non-Producing | 12.2 | 7.6 | 6.2 | 5.5 | 4.3 | 3.6 | 7.21 |
| Probable Undeveloped | 285.3 | 160.4 | 117.7 | 97.1 | 62.6 | 42.7 | 5.77 |
| **Total Probable** | **377.6** | **221.3** | **167.1** | **140.7** | **96.0** | **69.4** | **6.90** |
| **Total Proved plus probable** | **852.8** | **570.4** | **464.2** | **409.9** | **312.1** | **248.6** | **7.40** |

(1) January 1, 2018 McDaniel forecast prices and costs.
(2) May not add due to rounding.
(3) The unit values are based on net reserve volumes.

McDaniel's NPV10 estimate of Perpetual's total proved plus probable reserves at year-end 2017 was $409.9 million, up 8% from $380.7 million at year-end 2016. The increase in NPV10 reflected recycle ratios at East Edson driven by better well performance, combined with lower FDC in 2017, which offset the impact of lower forecast commodity prices. At a 10% discount factor, total proved reserves account for 66% (2016 – 55%) of the proved plus probable value. Proved plus probable producing reserves represent 41% (2016 – 26%) of the total proved plus probable value (discounted at 10%).

## FAIR MARKET VALUE OF UNDEVELOPED LAND

Perpetual's independent third-party estimate of the fair market value of its undeveloped acreage by region for purposes of the NAV calculation is based on past Crown land sale activity, adjusted for tenure and other considerations. In West Central Alberta, no undeveloped land value was assigned where proved and/or probable undeveloped reserves have been booked.

**Fair Market Value of Undeveloped Land**

| | **Net Acres** | **Value (*$ millions*)** | **$/Acre** |
|---|---|---|---|
| Eastern and other | 69,586 | 2.4 | 34.71 |
| West Central | 72,214 | 25.5 | 353.13 |
| Oil Sands | 188,640 | 18.8 | 99.58 |
| **Total** | **330,440** | **46.7** | **141.38** |

The fair market value of Perpetual's undeveloped land at year-end 2017, adjusted to remove the value of undeveloped lands with reserves assigned in West Central Alberta, is estimated by an external land consultant at $46.7 million, a decrease of 6% from $49.9 million relative to year-end 2016. The fair market value of undeveloped oil sands leases incorporates the absolute investment to date in the ongoing bitumen extraction pilot project at Panny and the undeveloped land value is also supported by recent land sale activity.

## NET ASSET VALUE

The following NAV table shows what is normally referred to as a "produce-out" NAV calculation under which the Corporation's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual's shares. The calculations below do not reflect the value of the Corporation's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment, except as they are valued through the estimate of the fair market value of undeveloped land.

**Pre-tax NAV at December 31, 2017(1)**

| | | Discounted at | | | |
|---|---|---|---|---|---|
| (*$ millions, except as noted*) | **Undiscounted** | **5%** | **8%** | **10%** | **15%** |
| Total Proved plus Probable Reserves(2) | 852.8 | 570.4 | 464.2 | 409.9 | 312.1 |
| TOU share investment(3) | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 |
| Fair market value of undeveloped land(5) | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 |
| Bank debt, net of working capital(1) | (48.0) | (48.0) | (48.0) | (48.0) | (48.0) |
| TOU share margin loan(1)(3)(4) | (18.5) | (18.5) | (18.5) | (18.5) | (18.5) |
| Term loan(4) | (45.0) | (45.0) | (45.0) | (45.0) | (45.0) |
| Senior notes(4) | (32.5) | (32.5) | (32.5) | (32.5) | (32.5) |
| Hedge book(6) | (14.1) | (14.1) | (14.1) | (14.1) | (14.1) |
| **NAV** | **779.4** | **497.0** | **390.8** | **336.5** | **238.7** |
| Common shares outstanding (*million*) | 59.3 | 59.3 | 59.3 | 59.3 | 59.3 |
| **NAV per share (*$/share*)** | **13.15** | **8.38** | **6.59** | **5.68** | **4.03** |

(1) Financial information is per Perpetual's 2017 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2017.
(3) TOU Share value based on 1.67 million shares at December 31, 2017 closing price ($22.78/share).
(4) Measured at principal amount.
(5) Independent third-party estimate; excludes undeveloped land in West Central Alberta with reserves assigned.
(6) Hedging adjustments, including shallow gas disposition obligations, as at December 31, 2017, relative to McDaniel's price forecast. Excludes market diversification contract values included in total proved plus probable reserves.

The above evaluation includes future capital expenditure expectations required to bring undeveloped reserves on production, as recognized by McDaniel's, that meet the criteria for booking under NI 51-101. Perpetual compiles annually a detailed internal estimate of the Corporation's total future decommissioning obligation based on net ownership interest in all wells, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites, and the estimated timing of the costs to be incurred in future periods. Costs inclusive in McDaniel's reserve assessment align closely with the Company's estimate of total future decommissioning obligations, net of estimated salvage value of facilities and equipment, therefore no additional future decommissioning obligation adjustment is included. The fair market value of undeveloped land does not reflect the value of the Company's extensive prospect inventory which is anticipated to be converted into reserves and production over time through future capital investment.

## 2018 OUTLOOK

In response to recent commodity market changes, Perpetual revised its 2018 capital plan to preserve the value of its East Edson natural gas reserves by deferring 2018 development drilling at East Edson and accelerating spending on highly economic heavy oil projects at Mannville, for a net 32% reduction to the 2018 capital budget to $23 to $27 million, down from $37 million initially set in November 2017. The revised capital plan is expected to result in the drilling of one (1.0 net) ERH liquids-rich natural gas well in 2018 along with three (3.0 net) completion and fracs at East Edson and up to 13 gross (12.3 net) horizontal heavy oil wells in the Mannville area. This resultant investment split is now more evenly distributed between the two core operating areas and natural gas and oil commodities.

With the capital re-allocation strategy to heavy oil, production in the first quarter of 2018 is expected to average close to 13,300 boe/d. Natural gas production declines are anticipated to reverse in the fourth quarter with the planned late third quarter frac of the East Edson ERH well to coincide with expected higher seasonal natural gas prices. Perpetual forecasts year-over-year average annual production growth of 17% to approximately 11,500 boe/d for 2018 and anticipates to exit the year at approximately 10,700 boe/d (17% oil and NGL).

Based on the capital spending plan and production assumptions outlined above, and the current forward market for oil and natural gas prices at market pricing points, Perpetual forecasts 2018 adjusted funds flow of $33 to $37 million ($0.56/share to $0.62/share). Further detailed information regarding the Company's 2018 outlook, including adjusted funds flow guidance assumptions and sensitivities, is available in "*Management's Discussion and Analysis – 2018 Outlook*" on page 13 of this annual report.

## FINANCIAL AND OPERATING HIGHLIGHTS

| | Three Months ended December 31 | | | Year ended December 31 | | |
|---|---|---|---|---|---|---|
| *($Cdn thousands, except volume and per share amounts)* | **2017** | 2016 | Change | **2017** | 2016 | Change |
| **Financial** | | | | | | |
| Oil and natural gas revenue | **23,810** | 17,940 | 33% | **81,722** | 81,403 | 0% |
| Net earnings (loss) | **(6,498)** | 20,379 | (132%) | **(35,971)** | 107,149 | (134%) |
| Per share – basic[2] | **(0.11)** | 0.39 | (128%) | **(0.62)** | 2.11 | (129%) |
| Per share – diluted | **(0.11)** | 0.37 | (130%) | **(0.62)** | 1.98 | (131%) |
| Cash flow from (used in) operating activities | **10,953** | 4,740 | 131% | **19,170** | (7,136) | 369% |
| Per share[1][2] | **0.18** | 0.09 | 106% | **0.33** | (0.14) | 335% |
| Adjusted funds flow[1] | **12,541** | 3,326 | 277% | **31,093** | 920 | 3280% |
| Per share[2] | **0.21** | 0.06 | 250% | **0.54** | 0.02 | 2600% |
| Revolving bank debt | **31,581** | – | 100% | **31,581** | – | 100% |
| Senior Notes, at principal amount | **32,490** | 60,573 | (46%) | **32,490** | 60,573 | (46%) |
| Term Loan, at principal amount | **45,000** | – | 100% | **45,000** | – | 100% |
| TOU share margin loans, at principal amount | **18,490** | 39,953 | (54%) | **18,490** | 39,953 | (54%) |
| TOU share investment | **(37,985)** | (66,343) | (43%) | **(37,985)** | (66,343) | (43%) |
| Net working capital deficiency[1] | **16,404** | 3,917 | 319% | **16,404** | 3,917 | 319% |
| Total net debt[1] | **105,980** | 38,100 | 178% | **105,980** | 38,100 | 178% |
| Net capital expenditures | | | | | | |
| Capital expenditures | **19,047** | 7,069 | 169% | **73,035** | 14,580 | 401% |
| Geological and geophysical costs | **–** | (3) | (100%) | **(22)** | 23 | (196%) |
| Net payments (proceeds) on acquisitions and dispositions | **970** | 1,785 | (46%) | **2,422** | (5,972) | (141%) |
| Net capital expenditures | **20,017** | 8,851 | 126% | **75,435** | 8,631 | 774% |
| **Common shares outstanding** *(thousands)*[3] | | | | | | |
| End of period[4] | **59,263** | 53,421 | 11% | **59,263** | 53,421 | 11% |
| Weighted average – basic | **59,338** | 52,924 | 12% | **58,017** | 50,733 | 14% |
| Weighted average – diluted | **59,338** | 54,678 | 9% | **58,017** | 54,038 | 7% |
| **Operating** | | | | | | |
| Average production | | | | | | |
| Natural gas *(MMcf/d)* | **60.8** | 40.3 | 51% | **49.6** | 74.7 | (34%) |
| Oil *(bbl/d)* | **888** | 936 | (5%) | **948** | 1,058 | (10%) |
| NGL *(bbl/d)* | **738** | 467 | 58% | **655** | 614 | 7% |
| Total *(boe/d)* | **11,765** | 8,118 | 45% | **9,876** | 14,128 | (30%) |
| Average prices | | | | | | |
| Realized natural gas price *($/Mcf)* | **3.22** | 2.41 | 34% | **3.51** | 2.42 | 45% |
| Realized oil price *($/bbl)* | **47.30** | 38.95 | 21% | **41.62** | 37.60 | 11% |
| Realized NGL price *($/bbl)* | **54.17** | 46.99 | 15% | **46.60** | 35.45 | 31% |
| **Wells drilled** | | | | | | |
| Natural gas – gross (net) | **3 (3.0)** | 3 (3.0) | | **15 (14.4)** | 4 (4.0) | |
| Oil – gross (net) | **–** | – | | **4 (3.3)** | – | |
| Total – gross (net) | **3 (3.0)** | 3 (3.0) | | **19 (17.7)** | 4 (4.0) | |

(1) These are non-GAAP measures.
(2) Based on weighted average basic common shares outstanding for the period.
(3) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. All common shares are net of shares held in trust.
(4) Reduced by shares held in trust (2017 – 447; 2016 – 260). See "Note 15 to the Audited Consolidated Financial Statements".

## ADVISORIES

The letter to shareholders and 2017 annual highlights refer to certain non-GAAP measures and metrics commonly used in the oil and natural gas industry and provides forward-looking information and statements. Further detailed information regarding these measures is provided in "*Management's Discussion and Analysis – Advisories*" on page 11, 32 and 33 of this annual report.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2017 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is February 22, 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 netbacks", "cash costs", "gas over bitumen revenue, net of payments", "net working capital deficiency (surplus)", "net debt and 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 operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate operating performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from 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 as a key measure to assess the ability of the Company to generate the funds necessary to finance operating activities and capital expenditures. Adjusted funds flow excludes the change in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such, may not be useful for evaluating Perpetual's operating performance. To make reported adjusted funds flow in this MD&A more comparable to industry practice, the Company reclassifies certain exploration and evaluation costs from operating to investing activities in the adjusted funds flow reconciliation. These exploration and evaluation costs include dry hole costs in addition to geological and geophysical costs, which are expensed in the period incurred. The Company has also reclassified the change in gas over bitumen royalty financing from financing to operating activities in the calculation of adjusted funds flow, in order to present these payments net of gas over bitumen royalty credits. 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 Properties, which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating earnings per share. Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS.

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

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| *($ thousands, except per share amounts)* | **2017** | 2016 | **2017** | 2016 |
| Net cash flows from (used in) operating activities | **10,953** | 4,740 | **19,170** | (7,136) |
| Changes in non-cash working capital | **779** | (2,539) | **9,480** | 4,910 |
| Expenditures on decommissioning obligations | **912** | 370 | **2,336** | 3,803 |
| Exploration and evaluation - geological and geophysical costs | **–** | (3) | **(22)** | 23 |
| Change in gas over bitumen royalty financing | **(337)** | (726) | **(2,421)** | (2,164) |
| Payments of restructuring costs | **234** | 1,484 | **2,550** | 1,484 |
| Adjusted funds flow | **12,541** | 3,326 | **31,093** | 920 |
| Adjusted funds flow per share | **0.21** | 0.06 | **0.54** | 0.02 |

Adjusted funds flow netbacks: Adjusted funds flow netbacks are determined by deducting general and administrative expenses, cash financing costs, gas over bitumen royalty credits net of payments and exploration and evaluation lease rental costs from operating netbacks. Management uses adjusted funds flow netbacks as a key measure to assess its overall profitability per boe, relative to current commodity prices.

Cash costs: Management believes that cash costs assist management and investors in assessing Perpetual's efficiency and overall cost structure. Cash costs are comprised of royalties, production and operating, transportation, general and administrative and cash finance expenses.

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 bank indebtedness 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 TOU share margin loans 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 (described below) share investment, TOU share margin loans and current portion of provisions.

Operating netback: Perpetual considers operating netback 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 average boe production 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, excluding 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 and basis differentials. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices, 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 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.

## 2017 FINANCIAL RESULTS

The strategic focusing of our asset base, strengthening of our balance sheet and effective execution of our growth-oriented capital program delivered attractive results in 2017.

Our focus in 2017 was enabled by the disposition on October 1, 2016 of 5,900 boe/d of mature, high cost shallow gas assets in east central and northeast Alberta for nominal cash consideration and the transfer of $128.0 million of associated decommissioning obligations to the purchaser (the "Shallow Gas Properties"). At the time of sale, the Shallow Gas Properties represented 42% of total production and 18% of proved plus probable reserves. The disposition was the primary reason for the $3.9 million improvement in adjusted funds flow in the fourth quarter of 2016 compared to the third quarter of 2016 and contributed to improved full year 2017 financial performance relative to 2016.

Our balance sheet was strengthened in early 2017 through the execution of a series of financing transactions. We extended the repayment term of $17.9 million of Senior Notes to 2022 that previously were scheduled to mature in 2018 and 2019. We issued $45 million of second lien term loans due in 2021 and raised gross proceeds of $9.0 million through the private placement of common shares and warrants. We early redeemed $27.1 million of Senior Notes that were scheduled to mature in 2018.

Our strengthened balance sheet provided the foundation to invest in our liquids-rich gas, West Central core area and our heavy oil properties located in eastern Alberta. Exploration and development capital spending in 2017 was $73.0 million, a five-fold increase over 2016, adding proved plus probable reserves equivalent to 248% of 2017 production at a finding and development ("F&D") cost of $6.16/boe (finding development and acquisition ("FD&A") cost of $5.98/boe). Our FD&A recycle ratio (operating netback/FD&A cost) for 2017 was an attractive 2.4 times.

Production for the fourth quarter of 2017 averaged 11,765 boe/d, increasing 45% over the prior year period. Production for the 2017 year was 9,876 boe/d, down 30% from 2016 reflecting the sale of the Shallow Gas Properties. Cash costs comprised of royalties, production and operating, transportation, general and administrative and cash finance expenses decreased by 17% in the fourth quarter of 2017 compared to the prior year period to $11.92/boe, due to diligent cost management and the impact of increased production in 2017 on a substantially fixed cost base. For the year ended December 31, 2017, cash costs were $14.77/boe, down 10% compared to 2016.

Realized revenue per boe was $23.60/boe in the fourth quarter of 2017 and $23.59/boe for the 2017 year, up 29% and 42% over the prior year comparable periods, respectively. Improved oil and natural gas liquids ("NGL") commodity prices combined with improved realized natural gas prices driven by hedging and price optimization strategies, contributed to the increase in realized revenue per boe in 2017.

Cash flow from operating activities in the fourth quarter of 2017 was $11.0 million or $0.18/share, up 131% over the prior year comparable period. Cash flow from operating activities for the year ended December 31, 2017 was $19.2 million or $0.33/share, compared to cash used in operating activities of $7.1 million or $0.14/share in the prior year period.

Adjusted funds flow in the fourth quarter of 2017 was $12.5 million or $0.21/share, up 277% over the prior year comparable period. Adjusted funds flow for the 2017 year was $31.1 million or $0.54/share, compared to $0.9 million or $0.02/share in the prior year period.

## 2018 OUTLOOK

In response to material commodity market changes, Perpetual has revised its 2018 capital plan to preserve the value of its East Edson reserves by deferring any additional 2018 development drilling at East Edson in West Central Alberta and accelerating spending on highly economic heavy oil projects at Mannville in eastern Alberta, for a net reduction to the 2018 capital budget to $23 - $27 million. On November 10, 2017, the Company announced that the Board of Directors approved a capital spending program of $37 million for 2018, close to 75% concentrated in East Edson, developing natural gas reserves with liquids in the Wilrich formation, and 25% in eastern Alberta, primarily targeting heavy oil development at Mannville. The forward average AECO and WTI prices for Calendar 2018 as of November 9, 2017 were $2.01 per GJ (US$3.09 per MMBtu NYMEX) and US$56.91 per bbl, respectively. The revised capital plan accounts for the wind down of gas focused drilling activities at East Edson and results in a modified capital plan with investment split more evenly between the two core operating areas and natural gas and oil commodities.

Although NYMEX natural gas prices have remained relatively steady as natural gas storage has been depleted through the winter to below historical levels driven by strong demand, the basis differential to Western Canadian markets has widened and AECO forward natural gas prices have weakened materially over the same period. Perpetual's five-year market diversification contracts that came into effect on November 1, 2017 have substantially mitigated the impact on adjusted funds flow of lower AECO prices, as the contracts appreciate in value with wider differentials to each of the five market price points. However, Perpetual measures economic returns for all new natural gas investments against current unhedged AECO strip pricing, as incremental volumes, net of royalties, would be effectively sold to this market. At the same time, the forward market for West Texas Intermediate oil has strengthened, translating into slightly stronger expected prices for Perpetual's blend of heavy oil, condensate and natural gas liquids ("NGL").

Perpetual's two core areas of operation provide a diversified portfolio of investment opportunities. The Company will remain flexible to reallocate spending between natural gas focused projects at East Edson and heavy oil projects depending on where the most profitable economics can be secured. For the first quarter, the one outstanding frac of the third extended reach horizontal ("ERH") well at East Edson will be postponed until late in the third quarter of 2018. Perpetual will re-direct spending to its heavy oil development project of the Birch General Petroleum A pool in Mannville, including a four well multi-lateral horizontal drilling program along with water handling and disposal facilities, previously budgeted for the second half of 2018. Assuming continued weakness in AECO natural gas prices, the four-well East Edson drilling program previously planned for the third quarter of 2018 will be deferred pending stronger AECO natural gas prices. Three (2.3 net) development wells at Mannville are expected to proceed as planned in the third quarter, along with three to six (3.0 to 6.0 net) additional wells at Mannville to evaluate the future horizontal development potential of three undeveloped heavy oil pools.

The table below summarizes planned capital spending and drilling activities for the first and second half of 2018.

### Exploration and Development Forecast Capital Expenditures

| | H1 2018 $ millions | # of wells (gross/net) | H2 2018 $ millions | # of wells (gross/net) | Total 2018 $ millions | # of wells (gross/net) |
|---|---|---|---|---|---|---|
| West Central | 8 | 1/1.0 | 3 | 0/0.0 | 11 | 1/1.0 |
| Eastern | 6 | 4/4.0 | 6 – 10 | 6 – 9/5.3 – 8.3 | 12 – 16 | 10 –13/9.3 – 12.3 |
| Total(1)(2) | **14** | **5/5.0** | **9 – 13** | **6 – 9/5.3 – 8.3** | **23 – 27** | **11 – 14/10.3 – 13.3** |

(1) Excludes expected decommissioning expenditures of $2.0 to $2.5 million in 2018.
(2) Previous capital spending forecast released November 10, 2017 included forecast total exploration and development capital spending of $37 million. Please see news release dated November 10, 2017 for details.

### Production Guidance

With the accelerated availability of increased firm transportation on TCPL, coupled with the capital re-allocation strategy to heavy oil, first quarter 2018 production is expected to average close to 13,300 boe/d, approximately 1,100 boe/d higher than previously forecast. Natural declines at East Edson will decrease natural gas and NGL production during the second and third quarters when AECO gas prices are expected to be at their lowest levels for the year. Then production will ramp up again with the planned late third quarter frac of the ERH well waiting on completion. Based on total exploration and development capital spending in 2018 of $23 to $27 million, Perpetual forecasts production to average approximately 11,500 boe/d for 2018 and forecasts to exit the year at approximately 10,700 boe/d (17% oil and NGL) as gas production at East Edson declines and Mannville heavy oil production ramps up driven by increased drilling and waterflood activity. While the growth in average daily production will be diminished from the original budget plan of 32%, year-over-year growth is still expected to be 17%, with a higher proportion of oil and NGL than previously forecast.

### Marketing and Hedging Update

Concurrent with the 2016 sale of the Shallow Gas Properties, Perpetual entered into commodity price contracts whereby Perpetual was obligated to provide an AECO floor price of $2.58/GJ on 33,611 GJ/d through August 31, 2018. Perpetual's obligation has now been fixed at a cost of $8.5 million in 2018.

During the third quarter of 2017, Perpetual diversified its natural gas price exposure from AECO by entering into arrangements to effectively shift the sales point of 34.1 MMcf/d to a basket of five North American natural gas hub pricing points for a five-year period commencing November 1, 2017, increasing to 39.0 MMcf/d commencing April 1, 2018. Based on current futures prices, these market diversification contracts will provide a significant premium over AECO prices in 2018 and provide significant diversification to Perpetual's natural gas pricing point exposure (net of royalties) as detailed below:

**Market/Pricing Point**

| Natural gas | Estimated Proportion of 2018 Production |
|---|---|
| AECO(1) | 0% |
| AECO fixed price | 27% |
| Empress | 5% |
| Dawn | 11% |
| Michcon | 7% |
| Chicago | 18% |
| Malin | 16% |
| Total natural gas | 84% |
| Natural gas liquids – Condensate(1) | 3% |
| Natural gas liquids – Other(1) | 2% |
| Crude oil – Fixed | 3% |
| Crude oil – Floating(1) | 8% |
| Total | 100% |

(1) Net of royalties.

**Adjusted Funds Flow and Sensitivities**

The following revised 2018 guidance assumptions, based on settled and forward 2018 market prices as at January 25, 2018 and operations assumptions as outlined above, have been used:

- Exploration and development capital spending of $23 to $27 million;
- 2018 average daily production of 11,500 boe/d (17% oil and NGL);
- Calendar 2018 average NYMEX gas price of US$2.98 per MMBtu;
- Calendar 2018 average West Texas Intermediate ("WTI") oil price of US$63.54 per bbl;
- Calendar 2018 average Western Canadian Select ("WCS") differential of (US$23.83) per bbl;
- Calendar 2018 average NYMEX to AECO basis differential of (US$1.77) per MMBtu;
- Calendar 2018 average CAD/US$1.00 exchange rate of 1.235; and
- 2018 cash costs, including royalties, of $13.00 to $14.00 per boe, increased slightly from previous outlook due to the impact of lower forecast production volumes on a mainly fixed cost structure.

Based on the capital spending plan and production assumptions outlined above, and the current forward market for oil and natural gas prices at market pricing points, Perpetual forecasts 2018 adjusted funds flow of $33 to $37 million ($0.56/share to $0.62/share) down from $35 to $40 million previously forecast in its news release dated November 10, 2017 due to lower forecast production and natural gas pricing.

Over the past year, natural gas prices at AECO have become disconnected from the North American market as resource development in the Western Canadian Sedimentary Basin has outpaced market access and market demand. Perpetual's market diversification contracts were put in place to mitigate the risk of lower AECO pricing due to widening of the basis differentials relative to various other markets and enable price participation in NYMEX-based markets. Incorporating the assumptions outlined above, and presuming NYMEX and AECO basis differentials remain constant to each of the diversified natural gas pricing points, Perpetual's estimated adjusted funds flow sensitivity to various commodity prices is as follows:

**Projected 2018 Adjusted Funds Flow Sensitivities(1)(2)**

| | | Calendar 2018 NYMEX price (*$US/MMBtu*) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | (*$CAD millions*) | **$2.25** | **$2.50** | **$2.75** | **$3.00** | **$3.25** | **$3.50** | **$3.75** |
| **Calendar 2018 WTI price (*$US/bbl*)** | **$45.00** | 20.7 | 22.8 | 24.8 | 26.9 | 29.0 | 31.1 | 33.2 |
| | **$50.00** | 22.5 | 24.5 | 26.6 | 28.7 | 30.8 | 32.9 | 35.0 |
| | **$55.00** | 25.3 | 27.4 | 29.5 | 31.6 | 33.7 | 35.8 | 37.8 |
| | **$60.00** | 28.0 | 30.1 | 32.2 | 34.2 | 36.3 | 38.4 | 40.5 |
| | **$65.00** | 29.8 | 31.9 | 33.9 | 36.0 | 38.1 | 40.2 | 42.3 |
| | **$70.00** | 31.6 | 33.7 | 35.7 | 37.8 | 39.9 | 42.0 | 44.1 |
| | **$75.00** | 33.4 | 35.4 | 37.5 | 39.6 | 41.7 | 43.8 | 45.9 |

(1) Sensitivities assume non-AECO market price points adjust commensurately and the Calendar 2018 AECO basis and WCS differentials are fixed at (US$1.77)/MMBtu and (US$23.83)/bbl respectively.

(2) The current settled and forward average NYMEX, WTI, NYMEX to AECO basis differential and WCS prices for Calendar 2018 as at February 6, 2018, were US$2.88/MMBtu, US$61.25/bbl, (US$1.73)/MMBtu, (US$25.60)/bbl respectively. The CAD/US$1.00 exchange rate for Calendar 2018 as at February 6, 2018 was 1.249.

The following additional sensitivities can be applied to estimate additional changes to projected 2018 adjusted funds flow:

- For every $0.25 USD/MMBtu widening or increase (narrowing or decrease) in the Calendar 2018 NYMEX to AECO basis differential, adjusted funds flow increases (decreases) by $4.4 million;
- For every $5.00 USD/bbl widening or increase (narrowing or decrease) in the Calendar 2018 WCS differential, adjusted funds flow decreases (increases) by $1.6 million; and
- For every $0.01 increase (decrease) in the Calendar 2018 CAD/US$1.00 exchange rate, adjusted funds flow increases (decreases) by $0.9 million.

At the current forward market for natural gas and oil prices, 2018 adjusted funds flow is expected to exceed capital spending and other obligations. Year-end 2018 net debt, net of the current market value of the Company's investment in shares of Tourmaline Oil Corp. ("TOU" – TSX) of close to $35 million, is forecast at $105 to $110 million, with a corresponding estimated net debt to trailing twelve months adjusted funds flow ratio of approximately 3.2 times. The year-end 2018 net debt forecast is based on net debt at December 31, 2017 of $106.0 million, plus 2018 capital spending of $23 to $27 million, 2018 decommissioning expenditures of $2.0 to $2.5 million, funding of Shallow Gas Property marketing obligation of $8.5 million, less 2018 adjusted funds flow of $33 to $37 million.

## 2017 CAPITAL EXPENDITURES

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands*) | **2017** | 2016 | **2017** | 2016 |
| Exploration and development | **19,028** | 7,044 | **72,956** | 14,039 |
| Other | **19** | 25 | **79** | 541 |
| Capital expenditures | **19,047** | 7,069 | **73,035** | 14,580 |
| Geological and geophysical costs(1) | **–** | (3) | **(22)** | 23 |
| Acquisitions | **–** | – | **432** | 12 |
| Net payments (proceeds) on dispositions | **970** | 1,785 | **1,990** | (5,984) |
| Total | **20,017** | 8,851 | **75,435** | 8,631 |

(1) Geological and geophysical costs and dry hole costs are expensed directly in the Corporation's consolidated statement of income (loss); they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures for the purposes of this MD&A.

In the fourth quarter of 2017, three (3.0 net) East Edson wells were drilled, with two having been completed in the first quarter of 2018. Additional compression was added at the 100% owned and operated West Wolf Lake 10-3 plant, to align compression and process capacity at the facility, bringing the plant capacity to 65 MMcf/d, and area capacity to 78 MMcf/d including the 15% working interest capacity held at a third-party operated facility in Rosevear. This expansion was completed in December 2017 for $2.1 million, on budget and three months ahead of schedule to accommodate the accelerated availability of increased firm transportation on TCPL to 78 MMcf/d from April 1, 2018 to December 17, 2017.

### *Exploration and development spending by area*

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands*) | **2017** | 2016 | **2017** | 2016 |
| West Central | **17,789** | 3,897 | **65,130** | 10,538 |
| Eastern | **1,239** | 3,147 | **7,826** | 3,501 |
| Total | **19,028** | 7,044 | **72,956** | 14,039 |

Perpetual's exploration and development spending in 2017 totaled $73.0 million, a five-fold increase over $14.0 million in 2016. Compared to Perpetual's capital spending outlook provided with its third quarter 2017 MD&A, spending was at the low end of the range as the drilling of one well at East Edson was deferred until the first quarter of 2018. Approximately 90% of Perpetual's exploration and development spending during the fourth quarter and year ended December 31, 2017 was focused on liquids-rich natural gas development activities in West Central Alberta.

Spending on West Central liquids-rich gas projects for 2017 included $65.1 million for the drilling of 14 (13.4 net) natural gas wells, with 13 (13.0 net) in the Company's East Edson area. Drilling and completion operations continued into the first quarter of 2018 at East Edson, with one (1.0 net) additional liquids-rich gas well drilled and two (2.0 net) wells completed since year end.

A total of $7.8 million was spent in the Mannville area during 2017, drilling one (1.0 net) exploratory natural gas well and four (3.3 net) oil wells. The remaining activity was primarily directed towards waterflood optimization with the conversion of one new injector, one new disposal well and pipeline construction for water management. Perpetual plans to drill and complete up to four horizontal multi-leg oil wells and install additional waterflood infrastructure at Mannville in the first quarter of 2018. Low variable operating costs and synergy with well abandonment programs in the Mannville area result in gas recompletions paying out within 6-12 months even at low commodity prices. These will continue during 2018 with up to 20 recompletions planned.

### *Dispositions*

Net payments on dispositions were $1.0 million in the fourth quarter of 2017 and $2.0 million for the year ended December 31, 2017, and included $1.0 million and $2.9 million of net payments, respectively, associated with the retained marketing arrangements related to the Shallow Gas Property disposition in 2016. As part of the disposition of the Shallow Gas Properties, Perpetual provided the purchaser with AECO floor price protection at $2.58/GJ and retained price participation to the extent AECO prices exceed $2.81/GJ on 33,611 GJ/d from October 1, 2016 through to August 31, 2018. Net payments of $2.9 million were made in 2017 (2016 – $0.5 million) with respect to these retained marketing arrangements. As at December 31, 2017, the fair value of the remaining AECO floor price obligation recorded on Perpetual's balance sheet was $7.7 million. With the weakening of AECO forward prices early in 2018, the floor price obligation increased and has been extinguished at a cost of $8.5 million to be paid over the remaining marketing arrangement term, ending August of 2018. Net proceeds on dispositions, principally of undeveloped land and seismic data in the fourth quarter of 2017 was nil (Q4 2016 – payments of $1.2 million) and $0.9 million for the year ended December 31, 2017 (2016 – $6.5 million).

*Expenditures on decommissioning obligations*

For the fourth quarter of 2017 and the 2017 year, expenditures on decommissioning obligations were $0.9 million and $2.3 million, respectively. Decommissioning expenditures were focused primarily in the Mannville area. Six reclamation certificates were received in the fourth quarter of 2017 (2017 year – 35) from the Alberta Energy Regulator which will reduce mineral and surface lease rental payments and municipal property taxes going forward. Decommissioning expenditures declined in 2017 from $3.8 million in 2016, primarily as a result of the disposition of the Shallow Gas Properties. Expenditures of $2.0 million to $2.5 million are anticipated in 2018.

## SUMMARY OF QUARTERLY AND ANNUAL NET INCOME (LOSS)

| **Three months ended December 31,** | | **2017** | | 2016 |
|---|---|---|---|---|
| | **(*$ thousands*)** | **(*$/boe*)** | (*$ thousands*) | (*$/boe*) |
| Realized revenue(1) | **25,541** | **23.60** | 13,696 | 18.34 |
| Royalties(2) | **(2,651)** | **(2.45)** | (3,070) | (4.11) |
| Production and operating expenses | **(3,738)** | **(3.45)** | (1,604) | (2.15) |
| Transportation costs | **(1,479)** | **(1.37)** | (969) | (1.30) |
| Operating netback(1) | **17,673** | **16.33** | 8,053 | 10.78 |
| Unrealized gains (losses) on derivatives | **(1,729)** | **(1.60)** | 5,639 | 7.55 |
| Gas over bitumen royalty credit and other | **399** | **0.37** | 696 | 0.93 |
| Exploration and evaluation | **(156)** | **(0.14)** | 417 | 0.56 |
| General and administrative expense | **(2,850)** | **(2.63)** | (3,655) | (4.89) |
| Share-based payments, non-cash | **(887)** | **(0.82)** | (1,480) | (1.98) |
| Depletion and depreciation | **(9,415)** | **(8.70)** | (6,948) | (9.30) |
| Gain (loss) on dispositions | **(3,949)** | **(3.65)** | 19,515 | 26.13 |
| Restructuring costs | **–** | **–** | (4,720) | (6.32) |
| Impairment reversals | **–** | **–** | 6,900 | 9.24 |
| Finance expense | **(1,265)** | **(1.17)** | (4,722) | (6.32) |
| Change in fair value of TOU share investment | **(4,319)** | **(3.99)** | 684 | 0.92 |
| Net income (loss) | **(6,498)** | **(6.00)** | 20,379 | 27.30 |
| Net income (loss) per share – basic | **(0.11)** | | 0.39 | |

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $1.4 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2017 (Q4 2016- $1.9 million).

| **Years ended December 31,** | | **2017** | | 2016 |
|---|---|---|---|---|
| | **(*$ thousands*)** | **(*$/boe*)** | (*$ thousands*) | (*$/boe*) |
| Realized revenue(1) | **85,027** | **23.59** | 86,104 | 16.65 |
| Royalties(2) | **(11,973)** | **(3.32)** | (9,415) | (1.82) |
| Production and operating expenses | **(16,299)** | **(4.52)** | (35,019) | (6.77) |
| Transportation costs | **(5,051)** | **(1.40)** | (7,925) | (1.53) |
| Operating netback(1) | **51,704** | **14.35** | 33,745 | 6.53 |
| Unrealized gains on derivatives | **2,550** | **0.71** | 13,340 | 2.58 |
| Gas over bitumen royalty credit and other | **2,460** | **0.68** | 1,984 | 0.38 |
| Exploration and evaluation | **(3,283)** | **(0.91)** | (3,790) | (0.73) |
| General and administrative expense | **(11,943)** | **(3.31)** | (17,153) | (3.32) |
| Share-based payments, non-cash | **(4,310)** | **(1.20)** | (5,911) | (1.14) |
| Depletion and depreciation | **(33,436)** | **(9.28)** | (54,317) | (10.50) |
| Gain (loss) on dispositions | **(9,450)** | **(2.62)** | 21,605 | 4.18 |
| Restructuring costs | **–** | **–** | (5,638) | (1.09) |
| Impairment reversals | **–** | **–** | 6,900 | 1.33 |
| Finance expense(3) | **(7,592)** | **(2.11)** | (24,847) | (4.81) |
| Change in fair value of TOU share investment | **(22,671)** | **(6.29)** | 58,897 | 11.39 |
| Gain on Security Swap | **–** | **–** | 81,310 | 15.72 |
| Net income and dividends from gas storage investment | **–** | **–** | 1,024 | 0.20 |
| Net income (loss) | **(35,971)** | **(9.98)** | 107,149 | 20.72 |
| Net income (loss) per share – basic | **(0.62)** | | 2.11 | |

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $6.7 million in gross overriding royalty payments at East Edson for the year ended December 31, 2017 (2016 – $5.5 million).
(3) 2016 includes $0.3 million in cash transaction costs in relation to the Security Swap.

**Net income (loss)**

For the fourth quarter ended December 31, 2017, Perpetual recorded a net loss of $6.5 million ($0.11/share) compared to net income of $20.4 million ($0.39/share) in the prior year period. Net loss in the fourth quarter of 2017 included a loss on disposition of $3.9 million (Q4 2016 – $19.5 million gain) associated with the Shallow Gas Properties and an unrealized loss of $4.3 million on its TOU share investment (Q4 2016 – $0.7 million gain). Also included in the Q4 2016 net income was a net impairment reversal of $6.9 million. Excluding these items, the Company recorded net income in the fourth quarter of $1.7 million compared to a net loss of $6.7 million in the prior year period. Improved performance was due to higher realized commodity prices, cost reductions, increased production and lower depletion rates.

For the year ended December 31, 2017, Perpetual recorded a net loss of $36.0 million ($0.62/share) compared to net income of $107.1 million ($2.11/share) for 2016. The $143.1 million year-over-year decrease in net income was primarily due to the absence of the 2016 $81.3 million gain on exchange of Senior Notes for TOU share investment and resulting reduction in interest expense, the $81.6 million year-over-year decrease in the change in fair value of TOU share investment (2017 – $22.7 million loss, 2016 – $58.9 million gain) and the $36.5 million year-over-year decrease in gains on disposition (2017 – $8.8 million loss, 2016 – $27.8 million gain) principally due to the Shallow Gas Property disposition. Income (loss) from operating activities in 2017, before impairment losses (reversals), restructuring expense and loss (gain) on dispositions was $3.7 million compared to ($32.1 million), representing a $35.8 million improvement due to higher realized commodity prices and cost reductions in 2017, and the sale of the Shallow Gas Properties in 2016.

**Cash flow from operating activities**

For the fourth quarter ended December 31, 2017, cash flow from operating activities was $11.0 million, up 134% from $4.7 million in the prior year period, primarily due to higher realized commodity prices, cost reductions and a 45% increase in average daily production.

For the year ended December 31, 2017, cash flow from operating activities was $19.2 million, compared to negative $7.1 million in 2016. Year-over-year improvements in commodity prices combined with significant cost reductions in 2017 more than offset the impact of the 30% decline in average daily production from 2016 to 2017. Through the Company's diligent focus on controlling costs along with the impact of the Shallow Gas Property disposition, Perpetual has seen expense reductions in all areas compared to 2016. These reductions were partially offset by higher royalties caused by improving commodity prices.

**Adjusted funds flow**

For the fourth quarter ended December 31, 2017, adjusted funds flow was $12.5 million, a $9.2 million increase over the prior year period due to the 45% increase in production, higher realized commodity prices and lower costs compared to the prior year period.

For the year ended December 31, 2017, adjusted funds flow was $31.1 million compared to $0.9 million in 2016, consistent with outlook guidance provided with the Company's third quarter 2017 MD&A of $28 to $32 million. Improved performance was driven by higher realized commodity prices combined with significant cost reductions, partially offset by the 30% decline in average daily production in 2017 compared to 2016.

**Netbacks**

The following tables highlight Perpetual's operating and adjusted funds flow netbacks per boe for the three months and years ended December 31, 2017 and 2016:

| | Three months ended December 31, 2017 | | | Three months ended December 31, 2016 | | |
|---|---|---|---|---|---|---|
| *($/boe)* | **West Central** | **Eastern** | **Total** | West Central | Eastern | Total |
| **Boe operating netback** | | | | | | |
| Production (*boe/d*) | **9,894** | **1,871** | **11,765** | 6,444 | 1,674 | 8,118 |
| Total petroleum and natural gas revenue | **20.28** | **31.08** | **22.00** | 22.20 | 31.03 | 24.02 |
| Realized gains on derivatives | **–** | **–** | **1.60** | – | – | (5.68) |
| Royalties | **(2.26)** | **(3.44)** | **(2.45)** | (4.44) | (2.84) | (4.11) |
| Production and operating expenses | **(1.72)** | **(12.63)** | **(3.45)** | (2.18) | (2.03) | (2.15) |
| Transportation costs | **(1.23)** | **(2.10)** | **(1.37)** | (0.93) | (2.70) | (1.30) |
| Total operating netback | **15.07** | **12.91** | **16.33** | 14.65 | 23.46 | 10.78 |
| Gas over bitumen, net of payments and other | | | **0.06** | | | (0.04) |
| Exploration and evaluation – lease rentals | | | **(0.14)** | | | 0.57 |
| General and administrative expense | | | **(2.63)** | | | (4.89) |
| Finance expense, cash | | | **(2.02)** | | | (1.96) |
| Adjusted funds flow netback | | | **11.60** | | | 4.46 |

| ($/boe) | Year ended December 31, 2017 West Central | Eastern | Total | Year ended December 31, 2016 West Central | Eastern | Total |
|---|---|---|---|---|---|---|
| **Boe operating netback** | | | | | | |
| Production (*boe/d*) | **7,896** | **1,980** | **9,876** | 7,453 | 6,675 | 14,128 |
| Total petroleum and natural gas revenue | **20.84** | **29.98** | **22.67** | 15.91 | 15.56 | 15.74 |
| Realized gains on derivatives | **–** | **–** | **0.92** | – | – | 0.91 |
| Royalties | **(3.27)** | **(3.53)** | **(3.32)** | (2.63) | (0.91) | (1.82) |
| Production and operating expenses | **(2.68)** | **(11.88)** | **(4.52)** | (2.93) | (11.06) | (6.77) |
| Transportation costs | **(1.18)** | **(2.27)** | **(1.40)** | (0.94) | (2.19) | (1.53) |
| Total operating netback | **13.71** | **12.30** | **14.35** | 9.41 | 1.40 | 6.53 |
| Gas over bitumen, net of payments and other | | | **0.02** | | | (0.03) |
| Exploration and evaluation – lease rentals | | | **(0.20)** | | | (0.20) |
| General and administrative expense | | | **(3.31)** | | | (3.32) |
| Finance expense, cash | | | **(2.22)** | | | (2.89) |
| Dividends from gas storage facility investment | | | **–** | | | 0.10 |
| Adjusted funds flow netback | | | **8.64** | | | 0.19 |

For the fourth quarter ended December 31, 2017, operating netback of $16.33/boe ($17.7 million) increased 51% from $10.78/boe ($8.1 million) in the prior year period due to increased realized revenue per boe and lower royalties, despite significantly lower AECO natural gas index prices. Royalties per boe decreased in the fourth quarter of 2017 due to lower AECO natural gas index prices. Production and operating expenses per boe were higher in the fourth quarter of 2017 due to the absence of $1.8 million ($2.41/boe) of non-recurring credits recorded in the prior year period associated with the Shallow Gas Properties that were sold.

For the year ended December 31, 2017, Perpetual's operating netback of $14.35/boe ($51.7 million) increased 120% from $6.53/boe ($33.7 million) in 2016. This improvement was due primarily to the 42% ($6.94/boe) increase in realized revenue per boe, combined with a 33% ($2.25/boe) decrease in operating costs and 9% ($0.13/boe) decrease in transportation costs, which more than offset the 82% increase in royalties caused by higher reference prices than in 2016.

Perpetual's adjusted funds flow netback was $11.60/boe for the fourth quarter of 2017, up 160% over the prior year period due to improved operating netback performance and lower general and administrative costs due to staff and office space reductions implemented following the sale of the Shallow Gas Properties, combined with increasing production during 2017.

For the year ended December 31, 2017, Perpetual's adjusted funds flow netback was $8.64/boe compared to $0.19/boe in 2016, due to improved operating netback performance.

**Production**

| | Three months ended December 31, **2017** | 2016 | Years ended December 31, **2017** | 2016 |
|---|---|---|---|---|
| Natural gas (*MMcf/d*) | | | | |
| Eastern | **6.0** | 4.5 | **6.3** | 33.8 |
| West Central | **54.8** | 35.8 | **43.3** | 40.9 |
| Total natural gas[(1)] | **60.8** | 40.3 | **49.6** | 74.7 |
| Crude oil (*bbl/d*) | | | | |
| Eastern[(2)] | **869** | 917 | **929** | 1,041 |
| West Central | **19** | 19 | **19** | 17 |
| Total crude oil | **888** | 936 | **948** | 1,058 |
| Total NGL (*bbl/d*)[(3)] | **738** | 467 | **655** | 614 |
| Total production (*boe/d*) | **11,765** | 8,118 | **9,876** | 14,128 |

(1) Natural gas production yields a higher heat content (GJ/Mcf), resulting in higher realized natural gas prices. 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.

Fourth quarter production averaged 11,765 boe/d, up 3,647 boe/d or 45% from the prior year period production of 8,118 boe/d, due primarily to strong growth in West Central production driven by the 2017 drilling program. Total natural gas, oil and NGL production for the year ended December 31, 2017 of 9,876 boe/d was 30% lower than 2016 (14,128 boe/d), primarily reflecting the disposition of the Shallow Gas Properties on October 1, 2016, offset partially by the growth in West Central production throughout the year.

Natural gas production at West Central during the three months ended December 31, 2017 increased by 53% from the prior year period, contributing most of the Corporation's natural gas production growth in the fourth quarter of 2017. This growth reflects the ramp up from East Edson drilling, with ten (10.0 net) wells coming on stream during the first nine months. Perpetual's 2017 annual natural gas production of 49.6 MMcf/d decreased 34% from 2016 (74.7 MMcf/d), reflecting the sale of approximately 35.5 MMcf/d of eastern Alberta production related to the Shallow Gas Properties effective October 1, 2016.

During the second half of 2017, industry transportation maintenance activities restricted available capacity and temporarily depressed natural gas prices at AECO. In response, Perpetual voluntarily shut-in an average 500 boe/d of production at East Edson in the fourth quarter (2017 year – 245 boe/d) to take advantage of temporary situations where natural gas could be purchased at nominal cost and delivered against pre-sold volumes.

Consistent with increased capital spending and growing East Edson natural gas production, NGL production of 738 bbl/d in the three months ended December 2017 increased 58% from the same period in 2016 (467 bbl/d). Condensate production represented 62% of fourth quarter and 2017 full year NGL production (Q4 2016 – 69%; 2016 – 66%). On a full year basis, the increased production of East Edson liquids-rich natural gas resulted in a 7% increase in NGL production in 2017 (655 bbl/d) compared to 2016 (614 bbl/d).

Crude oil production in eastern Alberta was 5% lower in the fourth quarter of 2017 compared to the same period in 2016, as minimal capital was allocated to the area in the third and fourth quarters of 2017. The Company continues to see positive response from waterflood activities in several pools, mitigating production declines by restoring pressure support. Oil production of 948 bbl/d for 2017 was 10% lower than 2016 (1,058 bbl/d) mainly due to natural declines and minimal capital spending on crude oil drilling and waterflood activities after the first quarter of 2017.

**Commodity Prices**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| | **2017** | 2016 | **2017** | 2016 |
| **Reference prices** | | | | |
| AECO Daily Index (*$/GJ*) | **1.60** | 2.93 | **2.04** | 2.05 |
| AECO Daily Index (*$/Mcf*)[1] | **1.69** | 3.09 | **2.16** | 2.16 |
| Alberta Gas Reference Price (*$/GJ*)[2] | **1.62** | 2.48 | **2.02** | 1.81 |
| West Texas Intermediate ("WTI") light oil (*US$/bbl*) | **55.40** | 49.29 | **50.95** | 43.32 |
| Western Canadian Select ("WCS") differential (*US$/bbl*) | **(12.26)** | (14.32) | **(11.98)** | (13.84) |
| WCS average (*$CAD/bbl*)[3] | **54.79** | 46.51 | **50.66** | 39.20 |
| **Average Perpetual prices** | | | | |
| Natural gas (*$/Mcf*)[1] | | | | |
| AECO Daily Index | **1.69** | 3.09 | **2.16** | 2.16 |
| Heat Content Premium | **0.17** | 0.32 | **0.21** | 0.15 |
| Market Diversification Contracts | **0.19** | – | **0.06** | – |
| Realized gains (losses) on financial and physical gas derivatives | **0.71** | (0.74) | **0.80** | 0.30 |
| Realized gains (losses) on prompt month price optimization | **0.46** | (0.26) | **0.28** | (0.19) |
| Realized natural gas price (*$/Mcf*)[4] | **3.22** | 2.41 | **3.51** | 2.42 |
| Percent of AECO Daily Index | **191** | 78 | **163** | 112 |
| Premium to AECO Daily Index due to higher heat content | **10%** | 10% | **10%** | 7% |
| Realized oil price (*$/bbl*)[4] | **47.30** | 38.95 | **41.62** | 37.60 |
| Realized natural gas liquids ("NGL") price (*$/bbl*) | **54.17** | 46.99 | **46.60** | 35.45 |

(1) Converted from $/GJ using a standard 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 = $1.27 for the three months ended December 31, 2017 (Q4 2016 – 1.33) and 1.30 for the year ended December 31, 2017 (2016 – 1.33).
(4) Realized natural gas and oil prices includes physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives. Realized gains and losses from foreign exchange contracts are excluded.

Reduced North American production in the first half of 2017, as well as increased demand from LNG exports from the US Gulf of Mexico and pipeline exports to Mexico allowed the US supply demand balance to loosen causing NYMEX natural gas prices to increase 26% from US$2.46/MMBtu in 2016 to an average of US$3.11/MMBtu in 2017. In comparison, the AECO Monthly Index prices only increased 16% from $1.98/GJ in 2016 to $2.30/GJ in 2017. During 2017, AECO became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin has outpaced market access and market demand. The increase of WTI to US$50.95/bbl in 2017 from US$43.32/bbl in 2016 was related to the gradual reduction in global oil inventories during 2017 as a result of increased global demand of crude by 1.6 MMbbl/d over 2016 levels and the supply restrictions implemented by OPEC effective January 1, 2017 to the extent of 1.2 MMbbl/d along with an additional cut from select non-OPEC producers of up to 0.6 MMbbl/d.

**Revenue**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Petroleum and natural gas revenue | | | | |
| Natural gas[1] | **16,009** | 12,272 | **54,444** | 59,902 |
| Oil[1] | **4,122** | 3,647 | **16,139** | 13,529 |
| NGL | **3,679** | 2,021 | **11,139** | 7,972 |
| Total petroleum and natural gas revenue | **23,810** | 17,940 | **81,722** | 81,403 |
| Realized gains on derivatives[2] | **1,731** | (4,244) | **3,305** | 4,701 |
| Realized revenue | **25,541** | 13,696 | **85,027** | 86,104 |
| Unrealized gains (losses) on derivatives | **(1,729)** | 5,639 | **2,550** | 13,340 |
| Total revenue | **23,812** | 19,335 | **87,577** | 99,444 |
| Realized revenue *($/boe)* | **23.60** | 18.34 | **23.59** | 16.65 |
| Total revenue *($/boe)* | **22.00** | 25.89 | **24.29** | 19.23 |

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

Realized revenue was $25.5 million in the fourth quarter of 2017, up 86% from the prior year period due to a 45% increase in production combined with a 29% increase in average realized prices. Included in realized revenues in the fourth quarter of 2017, were $1.7 million in realized gains on derivatives comprised of $2.0 million of gains on natural gas hedges, partially offset by $0.3 million of losses on WTI and WCS differential hedges.

For the 2017 year, realized revenue was $85.0 million, down 1% from the prior year as a 30% decrease in production was offset by a similar increase in average realized prices. Included in realized revenues for the 2017 year, were $3.3 million in realized gains on derivatives comprised of $9.2 million of gains on natural gas hedges, partially offset by $1.7 million of losses from oil hedges and $4.2 million of losses on foreign exchange hedges.

Natural gas realized revenue in the fourth quarter of 2017 was $18.0 million, comprising 70% of total realized revenue while natural gas represented 86% of production on a boe/d basis. Compared to the prior year period, natural gas realized revenue increased by 102% in the fourth quarter of 2017, due to a 34% increase in realized natural gas prices and a 51% increase in production due to the ramp up of East Edson production during 2017. Realized natural gas prices in the fourth quarter of 2017 were $3.22/Mcf representing 191% of the AECO Daily Index price compared to 78% in the prior year period. Realized gains on financial and physical gas derivatives added $0.71/Mcf to the realized price in the fourth quarter (2016 – $0.74/Mcf loss). Realized gains on prompt month price optimization operations added $0.46/Mcf in the fourth quarter (2016 – $0.26/Mcf loss) and included $0.09/Mcf ($0.5 million) associated with the purchase of third party gas at nominal cost to deliver against pre-sold volume commitments. Effective November 1, 2017, Perpetual commenced sales to the five-year term, NYMEX based contract on 35.0 MMcf/d which contributed a $0.19/Mcf ($1.0 million incremental revenue) increase in Perpetual's average realized natural gas price compared to the AECO Daily Index in the fourth quarter. This contract increases to 40.0 MMcf/d effective April 1, 2018. On a pro forma basis, had the full 40.0 MMcf/d contract been in place for the entire fourth quarter, Perpetual's realized natural gas price would have increased by an additional $0.15/Mcf ($0.8 million additional revenue).

Oil realized revenue in the fourth quarter of 2017 was $3.9 million, comprising 15% of total realized revenue and 8% of production on a boe/d basis. Compared to the prior year, oil realized revenue increased by 15%, due to a 21% increase in price partially offset by a 5% reduction in production. Perpetual's realized oil price in the fourth quarter of 2017 of $47.30/bbl reflected increased WTI pricing combined with a reduced WCS differential compared to the prior year period. Included in Perpetual's average oil price are deductions for quality adjustments, loss allowance, terminal fees and diluent blending fees.

NGL revenue in the fourth quarter of 2017 was $3.7 million, comprising 14% of total realized revenue and 6% of production on a boe/d basis. Compared to the prior year period, NGL revenue increased by 82% in the fourth quarter of 2017 due to a 15% increase in price and a 58% increase in production associated with the ramp up in production at East Edson during 2017.

Unrealized losses on derivatives of $1.7 million were recorded in the fourth quarter of 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, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

**Royalties**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| *($ thousands, except as noted)* | **2017** | 2016 | **2017** | 2016 |
| Crown | **260** | 515 | **2,066** | 1,676 |
| Freehold and overriding[(1)] | **2,391** | 2,555 | **9,907** | 7,739 |
| Total | **2,651** | 3,070 | **11,973** | 9,415 |
| Crown (*% of P&NG revenue*) | **1.1** | 2.9 | **2.5** | 2.1 |
| Freehold and overriding (*% of P&NG revenue*) | **10.0** | 14.2 | **12.1** | 9.5 |
| Total (*% of P&NG revenue*) | **11.1** | 17.1 | **14.6** | 11.6 |
| $/boe | **2.45** | 4.11 | **3.32** | 1.82 |

(1) Includes $1.4 million in gross overriding royalty payments at East Edson ("East Edson GORR") for the three months ended December 31, 2017 (Q4 2016 – $1.9 million) and $6.7 million for the year ended December 31, 2017 (2016 – $5.5 million).

Royalty expense for the fourth quarter of 2017 was $2.7 million, representing 11.1% of total petroleum and natural gas revenue, down from $3.1 million and 17.1% respectively, in the prior year period. Lower royalty rates reflect the decrease in the Alberta Gas Reference Price and the AECO daily index price compared to the prior year period which are used to determine crown royalty and freehold and overriding royalty expense. At East Edson, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production. As East Edson production increases, the fixed nature of the gross overriding royalty results in a decreased expense on a percentage of revenue and unit of production basis, which also contributed to the reduced overriding royalty rate in the fourth quarter of 2017 compared to the prior period.

On an annual basis, royalty expenses for 2017 were $12.0 million, representing a 27% increase in the effective combined average royalty rate on P&NG revenue to 14.6% from 11.6% in 2016. Average crown royalty rates increased to 2.5% in 2017 compared to 2.1% in 2016, due primarily to higher Alberta natural gas reference prices and increasing oil prices.

**Production and operating expenses**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| *($ thousands, except as noted)* | **2017** | 2016 | **2017** | 2016 |
| Production and operating expenses | **3,738** | 1,604 | **16,299** | 35,019 |
| $/boe | **3.45** | 2.15 | **4.52** | 6.77 |

Production and operating expenses increased 133% to $3.7 million in the fourth quarter of 2017 compared to $1.6 million recorded during the same period in 2016. The fourth quarter of 2016 operating expenses include $1.8 million ($2.41/boe) of non-recurring adjustment credits associated with the sold Shallow Gas Properties. After adjusting for these non-recurring items, production and operating expenses decreased by 24% on a boe basis compared to the prior year period due to lower maintenance and repair costs, purchased energy costs, and processing fees combined with increased production from the low-cost East Edson property in West Central.

For the full year, production and operating expenses decreased 53% to $16.3 million in 2017 compared to $35.0 million in 2016. This decrease reflected company-wide cost saving initiatives, operating efficiencies at the low-cost Company owned and operated gas plant at East Edson, and the full year impact in 2017 of the sale of the high cost Shallow Gas Properties.

**Transportation costs**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Transportation costs | **1,479** | 969 | **5,051** | 7,925 |
| $/boe | **1.37** | 1.30 | **1.40** | 1.53 |

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. For the fourth quarter of 2017, transportation costs were $1.5 million, an increase of 52% over the prior year period, consistent with production volume increases. For the 2017 year, transportation costs decreased to $5.1 million from $7.9 million in 2016, reflecting lower oil and gas sales volumes combined with a higher percentage of gas production from West Central properties in 2017, where transportation costs averaged $1.18/boe compared to $2.27/boe for eastern Alberta.

The increase in firm transportation capacity on TCPL to 78 MMcf/d in late December 2017 is expected to increase 2018 transportation costs by approximately $1.0 million over 2017 levels.

**Gas over bitumen**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Gas over bitumen revenue | **151** | 696 | **2,116** | 1,984 |
| Payments on gas over bitumen royalty financing(1) | **(337)** | (726) | **(2,421)** | (2,164) |
| Gas over bitumen, net of payments | **(186)** | (30) | **(305)** | (180) |
| $/boe | **(0.17)** | (0.04) | **(0.08)** | (0.03) |

(1) At December 31, 2017, the fair value of the gas over bitumen royalty financing is estimated to be $2.7 million (2016 – $8.3 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During 2017, Perpetual recorded $2.1 million in gas over bitumen revenue; an increase of 7% ($0.1 million) from the same period in 2016 attributable to the 12% increase in Alberta Gas Reference Prices, partially offset by the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned throughout 2017 were offset by payments of $2.4 million (2016 – $2.2 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 credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen 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 as revenue in accordance with Perpetual's accounting policies with the monthly payments recognized separately 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 2017, the gas over bitumen royalty financing obligation was reduced by $5.6 million, comprised of payments of $2.4 million (2016 – $2.2 million) in addition to an unrealized gain of $3.2 million (2016 – loss of $0.5 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 compared to 2016, as a result of lower forecasted natural gas reference prices.

**Exploration and evaluation ("E&E")**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands*) | **2017** | 2016 | **2017** | 2016 |
| Lease rentals | **156** | (424) | **703** | 1,040 |
| Geological and geophysical costs(1) | **–** | (3) | **(22)** | 23 |
| Lease expiries | **–** | 10 | **2,602** | 2,727 |
| Total E&E expense | **156** | (417) | **3,283** | 3,790 |

(1) Geological and geophysical expenditures and dry hole costs are expensed directly in the Corporation's statement of income (loss); they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures for the purposes of this MD&A.

Total E&E expense includes lease rentals on undeveloped acreage, geological and geophysical costs and the write down of carrying costs related to lease expiries. E&E costs of $3.3 million in 2017 were 13% lower than 2016 due to decreased lease rental costs, geological and geophysical costs and fewer lease expiries. The reduction in lease rental costs was largely due to dispositions in 2016 along with decisions in 2016 and 2017 to let several leases expire, primarily in eastern Alberta.

**General and administrative ("G&A") expenses**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Cash G&A expense | **3,707** | 4,465 | **15,377** | 21,190 |
| Overhead recoveries | **(857)** | (810) | **(3,434)** | (4,037) |
| Total G&A expense | **2,850** | 3,655 | **11,943** | 17,153 |
| Total G&A expense *($/boe)* | **2.63** | 4.89 | **3.31** | 3.32 |

Total G&A expense in the fourth quarter of 2017 was $2.9 million and $11.9 million for the full year 2017, down 22% and 30% respectively, from prior period levels. Lower expenses resulted from staff and office space reductions in the fourth quarter of 2016 following the Shallow Gas Property disposition combined with diligent expense management. On a per boe basis, total G&A expense was $2.63/boe in the fourth quarter of 2017 and $3.31/boe for the 2017 year, down 46% and 1% respectively compared to the prior year periods driven by cost reductions combined with increasing production during 2017.

**Share-based payments**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Share-based payments expense (non-cash) | **887** | 1,480 | **4,310** | 5,911 |
| Share-based payments expense (non-cash) *($/boe)* | **0.82** | 1.98 | **1.20** | 1.14 |

Non-cash share-based payments expense for the year ended December 31, 2017 decreased $1.6 million compared to the same period in 2016. This decrease was the result of reductions in staffing levels following the Shallow Gas Property disposition in the fourth quarter of 2016.

**Restructuring costs**

| (*$ thousands, except as noted*) | **2017** | 2016 |
|---|---|---|
| Employee downsizing costs | – | 2,926 |
| Onerous office lease contract | – | 2,712 |
| Total restructuring costs | – | 5,638 |
| Restructuring costs *($/boe)* | – | 1.09 |

During 2016, the Company recognized onerous lease obligations totaling $2.7 million in relation to corporate office space which was no longer being utilized as a result of a terminated sublease and staff reductions related to the disposition of the Shallow Gas Properties. The unused office space was recorded as an onerous contract as the unavoidable costs associated with the lease contract exceeded the economic benefits to be received. Also included in restructuring costs was $2.9 million in relation to employee downsizing costs of which $1.3 million was paid in 2016 with the remainder paid out in 2017.

**Depletion and depreciation**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2017** | 2016 | **2017** | 2016 |
| Depletion and depreciation | **9,415** | 6,948 | **33,436** | 54,317 |
| $/boe | **8.70** | 9.30 | **9.28** | 10.50 |

Perpetual recorded $33.4 million of depletion and depreciation expense for the year ended December 31, 2017, down 38% from $54.3 million in 2016. On a per boe basis, 2017 depletion and depreciation expense of $9.28/boe was 12% lower than the prior year, due primarily to the lower depletion rates associated with the Company's East Edson assets, which make up a larger percentage of Perpetual's production on which depletion expense is recorded. The Company's 2017 capital program added proved plus probable reserves at FD&A costs of $5.98/boe which also contributed to lower depletion rates in 2017 compared to the prior year.

**Impairment**

For the year ended December 31, 2017, the Company assessed impairment indicators for the Company's Cash Generating Units ("CGUs"). There was no impairment or impairment reversal recognized in 2017.

For the year ended December 31, 2016, the Company assessed impairment indicators for the Company's CGUs. In performing the review, management determined that the disposition of the Shallow Gas Properties justified calculation of the recoverable amount of the Northern CGU. In addition, technical revisions to Mannville heavy oil reserves related to improved recovery methods along with realized lower operating costs and capital efficiencies justified a review for impairment reversals for the Eastern CGU. The Company determined the recoverable amount of Northern and Eastern CGUs using VIU based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators along with the associated year-end commodity price forecast, and an estimate of market discount rates between 12 and 20 percent to consider risks specific to the asset.

At December 31, 2016, the Company recorded a net impairment reversal of $6.9 million to net income which was comprised of the following:

- The Company determined that the carrying amount of the Northern CGU of $6.7 million exceeded the recoverable amounts. Accordingly, an impairment charge of $5.8 million was included in net income reducing the carrying amount to $0.9 million; and
- The Company determined that the recoverable amount of the Eastern CGU exceeded its carrying amount of $33.1 million by $15.9 million; accordingly, a reversal of $12.7 million was recognized in net income representing the full reversal of previously recorded impairments adjusted for depletion resulting in a carrying amount $45.8 million.

**Finance expenses**

| | Three months ended December 31, | | Years ended December 31, | |
|---|---|---|---|---|
| (*$ thousands*) | **2017** | 2016 | **2017** | 2016 |
| Cash interest | | | | |
| Interest on revolving bank debt | **314** | 129 | **1,078** | 2,749 |
| Interest on TOU share margin loans | **227** | – | **687** | – |
| Interest on Term Loan | **892** | – | **2,441** | – |
| Interest on Senior Notes | **755** | 1,325 | **3,798** | 11,942 |
| Total cash interest | **2,188** | 1,454 | **8,004** | 14,691 |
| Total cash interest *($/boe)* | **2.02** | 1.95 | **2.22** | 2.84 |
| Non-cash finance expense | | | | |
| Amortization of debt issue costs | **198** | 56 | **620** | 509 |
| Accretion on decommissioning obligations | **204** | 178 | **775** | 2,643 |
| Change in fair value of gas over bitumen royalty financing | **(1,325)** | 1,079 | **(3,184)** | 497 |
| Change in fair value of TOU share margin loans | **–** | 1,943 | **1,377** | 6,507 |
| Non-cash finance expense (recovery) | **(923)** | 3,256 | **(412)** | 10,156 |
| Finance expenses recognized in net income (loss) | **1,265** | 4,710 | **7,592** | 24,847 |

Total cash interest expense was $2.2 million in the fourth quarter of 2017, an increase of $0.7 million from the comparable prior year period primarily due to a 25% increase in year-over-year debt levels. Total cash interest expense for the 2017 year was $8.0 million, down $6.7 million from 2016 due to the cancellation during the second quarter of 2016 of $214.4 million principal amount 8.75% Senior Notes in exchange for 4.4 million TOU shares owned by Perpetual (the "Security Swap"), partially offset by higher year-over-year debt levels in 2017.

Non-cash finance expense was a recovery of $0.9 million in the fourth quarter of 2017 compared to an expense of $3.3 million in the prior year period. A reduction in the fair value of the gas over bitumen royalty obligation due to lower AECO future gas prices at December 31, 2017 contributed to $2.4 million of the variance with the remaining difference due to the absence of the change in the fair value of the TOU share put option margin loans of $1.9 million recorded in the fourth quarter of 2016 as these loans were refinanced in the third quarter of 2017 without embedded put option derivatives. For the 2017 year, non-cash finance expense was a recovery of $0.4 million compared to an expense of $10.2 million in 2016 due to the same factors that impacted the fourth quarter variance as well as a $1.9 million reduction in accretion on decommissioning obligations due to the $128.0 million reduction in decommissioning obligations that resulted from the disposition of the Shallow Gas Properties in 2016.

**Gain on exchange of Senior Notes for TOU share investment**

During the second quarter of 2016, the Company recorded a net gain of $81.3 million from the Security Swap transaction, whereby $114.0 million of outstanding 2018 Senior Notes and $100.4 million of outstanding 2019 Senior Notes were repurchased and cancelled through the exchange of 4.4 million TOU shares and cash payments of $3.9 million for accrued interest. The fair market value of TOU shares exchanged was $130.5 million based on an average closing price of $29.64 per share. Included in the Security Swap were $81.6 million 2018 Senior Notes and $57.0 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them.

**Change in fair value of TOU share investment**

During 2017, the Company recorded an unrealized loss of $22.7 million related to the change in fair value of TOU share investment, which represents the change in value of TOU shares held from December 31, 2016 ($35.91 per share) to December 31, 2017 ($22.78 per share). At December 31, 2017, Perpetual owned 1.67 million TOU shares (December 31, 2016 – 1.85 million shares) having a fair market value of $38.0 million (December 31, 2016 – $66.3 million).

**Gas storage facility investment**

During the second quarter of 2016, the Corporation disposed of its interest in a gas storage facility investment for net cash proceeds of $19.7 million, resulting in a net loss on disposition of $6.2 million. Prior to the disposition of the gas storage facility investment, Perpetual recorded income of $1.0 million and received dividends of $0.5 million, representing the Corporation's share of total dividends declared prior to the closing of the sale transaction. In 2017, a $0.7 million negative adjustment was recorded in connection with the disposition of the gas storage facility.

## LIQUIDITY, CAPITALIZATION AND FINANCIAL 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 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 loans and net working capital, with value and liquidity enhanced through the current ownership of TOU shares. In order 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.

During the year ended December 31, 2017, the Company completed several financing transactions to strengthen Perpetual's liquidity and debt repayment profile and secure funding for the Company's 2017 capital expenditure program. The significant financing transactions are as follows:

- Exchange of $17.4 million aggregate principal amount of its existing Senior Notes maturing in 2018 and 2019 for new 8.75% Senior Notes having an extended maturity date of January 23, 2022 (the "2022 Senior Notes"). The remaining $27.6 million Senior Notes maturing in 2018 were redeemed by cash repayment of $27.1 million and $0.5 million through an exchange for new 2022 Senior Notes;
- Establishment of the term loan with total availability of $45 million bearing annual interest at 8.1% and maturing March 14, 2021 (the "Term Loan"). In addition, for no additional consideration, 5.4 million warrants were issued and valued at $0.8 million which entitle the lender to acquire common shares on a one for one basis for a period of up to three years, at an exercise price of $2.34 per share (the "Warrants"). The initial draw on the Term Loan was $35 million with the second and final draw of $10 million occurring on October 5, 2017;
- Issuance of 5.1 million common shares and 1.1 million additional Warrants for aggregate gross proceeds of $9 million on March 14, 2017;
- Three borrowing base increases to the Company's reserve based, revolving bank debt (the "Credit Facility") comprised of a $14 million increase in March of 2017, a $20 million increase in July 2017 and a $25 million increase in November 2017 to a total borrowing limit of $65 million. Restricted cash of $2 million was released by the lender. The Credit Facility maturity date was extended to May 31, 2019; and
- Establishment of a new $18.7 million TOU share margin loan secured by 1.67 million TOU shares maturing in July 2018. Proceeds from the new margin loan along with borrowings under the Credit Facility were used to repay the $36.5 million TOU share put option margin loans that were scheduled to mature in August and November of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options.

**Capital Management**

| (*$ thousands, except as noted*) | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Revolving bank debt | **31,581** | – |
| Term Loan, measured at principal amount | **45,000** | – |
| TOU share margin loans, measured at principal amount | **18,490** | 39,953 |
| Senior Notes, measured at principal amount | **32,490** | 60,573 |
| TOU share investment(1) | **(37,985)** | (66,343) |
| Net working capital deficiency(2) | **16,404** | 3,917 |
| Net debt(2) | **105,980** | 38,100 |
| Shares outstanding at end of period (*thousands*)(3) | **59,263** | 53,421 |
| Market price at end of period (*$/share*)(3) | **1.10** | 2.35 |
| Market value of shares | **65,189** | 125,539 |
| Enterprise value(2) | **171,169** | 163,639 |
| Net debt as a percentage of enterprise value | **62** | 23 |
| Trailing twelve months adjusted funds flow(2) | **31,093** | 920 |
| Net debt to trailing twelve months adjusted funds flow | **3.4** | 41.4 |

(1) The TOU share investment is based on the December 31, 2017 closing price per the Toronto Stock Exchange ($22.78 per share) and 1.67 million TOU shares held (December 31, 2016 – 1.85 million TOU shares held with a closing price of $35.91 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2017, Perpetual had total net debt of $106.0 million, up $67.9 million (178%) from December 31, 2016. The increase reflects the increase in capital investment during the year combined with a $28.4 million reduction in the fair value of TOU shares.

As at December 31, 2017, Perpetual had available liquidity (defined as the Credit Facility Borrowing Limit plus TOU share investment, less borrowing and letters of credit issued under the Credit Facility and TOU share margin loan) of $49 million. As at December 31, 2017, 59% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved significantly during 2017 to 3.4 times at December 31, 2017.

Perpetual maintains credit ratings with Moody's and Standard & Poors ("S&P") that facilitate access to the high yield bond market to refinance existing debt or raise additional funding if required. On July 7, 2017, Moody's Investors Service announced that it had upgraded Perpetual's corporate credit rating from Caa2 – Negative Outlook to Caa1 – Stable Outlook. On November 20, 2017, S&P upgraded Perpetual's credit rating by two rating notches from CCC- to CCC+ with a stable outlook, based on Perpetual's improved liquidity.

**TOU share margin loans**

At December 31, 2017, Perpetual had an $18.4 million TOU share margin loan secured by 1.67 million TOU shares that matures on July 31, 2018 representing a 40% loan to TOU share value lending ratio at the date of funding. Interest rates are indexed to the same applicable Banker's Acceptance margins as the Credit Facility, ranging between 1.5% and 4.0%. 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 loan compared to the daily 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 loan to restore the lending ratio to 40%. As at December 31, 2017, the Lending Ratio was 48% of the closing market value of the pledged TOU shares. Subsequent to December 31, 2017, the TOU share price has declined in value, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the Lending

Ratio at less than 55%, funded from borrowings on its Credit Facility. The TOU share margin loan is designated as a financial liability measured at amortized cost.

Proceeds from this margin loan along with borrowings under its Credit Facility were used to repay the TOU share put option margin loans during the third quarter of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options.

Prior to repayment, the TOU share put option margin loans were hybrid financial instruments comprising a debt host with an embedded TOU share put option derivative related to indexation of the future settlement amount to changes in the market price of TOU shares pledged as collateral. The Company had designated the TOU share put option margin loans as financial liabilities which were measured at fair value through profit and loss. For the year ended December 31, 2017, an unrealized loss of $1.4 million (2016 – $6.5 million unrealized loss) is included in finance expense, representing the change in fair value of the TOU share put options during the year.

In addition to the Lending Ratio requirements, the TOU share margin loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin loan covenants at December 31, 2017.

**Revolving Bank Debt**

As at December 31, 2017, the Company's reserve-based Credit Facility had a borrowing limit (the "Borrowing Limit") of $65.0 million (December 31, 2016 – $6.0 million) under which $31.6 million was drawn (December 31, 2016 – nil) and $3.9 million of letters of credit had been issued (December 31, 2016 – $4.0 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 2.0% and 4.5% depending on the Company's ratio of net debt to adjusted funds flow.

The Credit Facility will continue to revolve until May 31, 2018 and may be extended for a further 364-day period subject to approval by the syndicate. If not extended, the Credit Facility will cease to revolve and all outstanding advances will be repayable on May 31, 2019. The next Borrowing Limit redetermination is scheduled on or prior to May 31, 2018.

Borrowings are secured by general security agreements covering all of the Company's assets with the exception of TOU shares that have been pledged as security for the TOU share margin loans and certain lands pledged to the gas over bitumen royalty financing counterparty.

The effective interest rate on the Credit Facility at December 31, 2017 was 4.3%. For the years ended December 31, 2017 and 2016, if interest rates changed by 1% with all other variables held constant, the annual impact on interest expense and net income (loss) would be $0.3 million (2016 – $0.1 million).

Prior to the July 4, 2017 Borrowing Limit redetermination, the Credit Facility was subject to a working capital covenant which required the Company to maintain net working capital plus outstanding letters of credit not exceeding the Borrowing Limit. Net working capital includes the sum of cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and unpledged TOU shares less accounts payable and accrued liabilities and accrued interest on Senior Notes and the Term Loan up to the Credit Facility maturity date. On July 4, 2017, as part of the Borrowing Limit redetermination, Perpetual's lenders removed this working capital covenant. The Credit Facility also contains provisions which restrict the Company's ability to pay dividends on or repurchase its common shares.

At December 31, 2017, 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.

| | **December 31, 2017** |
|---|---|
| Balance, beginning of period | $ – |
| Principal amount of Term Loan issued | **45,000** |
| Value allocated to Warrants issued | **(769)** |
| Issue costs | **(1,361)** |
| Amortization of issue costs | **363** |
| Balance, end of year | **$ 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. The $45 million Term Loan consisted of an initial draw of $35 million completed upon closing with the final $10 million drawn on October 5, 2017. 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 loan lenders and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2017, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

**Senior Notes**

| | Maturity date | Interest rate | December 31, 2017 Principal | December 31, 2017 Carrying Amount | December 31, 2016 Principal | December 31, 2016 Carrying amount |
|---|---|---|---|---|---|---|
| 2018 Senior Notes | March 15, 2018 | 8.75% | **$ –** | **$ –** | $ 36,013 | $ 35,847 |
| 2019 Senior Notes | July 23, 2019 | 8.75% | **14,572** | **14,476** | 24,560 | 24,273 |
| 2022 Senior Notes | January 23, 2022 | 8.75%(1) | **17,918** | **17,204** | – | – |
| | | | **$ 32,490** | **$ 31,680** | $ 60,573 | $ 60,120 |

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

On January 23, 2017, the Company exchanged $8.4 million and $9.0 million aggregate principal amount of 2018 Senior Notes and 2019 Senior Notes respectively for $17.4 million new 8.75% Senior Notes with a maturity date of January 23, 2022 (collectively, the "Senior Notes"). Included in the exchange were $3.7 million 2018 Senior Notes and $4.3 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them. The 2022 Senior Notes bear a fixed rate of 9.75% for the first year of issuance and 8.75% thereafter, and have identical covenants and rights as the existing 2018 and 2019 Senior Notes.

On April 17, 2017, Perpetual redeemed $27.1 million aggregate outstanding principal amount of its 8.75% Senior Notes maturing March 15, 2018 for cash and exchanged the remaining $0.5 million for the issuance of an equal amount of 2022 Senior Notes. In mid-July, $1.0 million face value of 2019 Senior Notes were purchased at 96.75% of face value and retired.

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% 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% of the Senior Notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100% of the Senior Notes at the principal amount.

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

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

At December 31, 2017 the Senior Notes are presented net of $0.8 million in issue costs which are amortized over the remaining term to maturity using a weighted average effective interest rate of 9.6%.

At December 31, 2017, in addition to 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**

Authorized capital consists of an unlimited number of common shares. On March 24, 2016, shareholders of the Company approved the consolidation of common shares on the basis of 20 common shares to one common share, which has been retroactively applied throughout this MD&A.

On March 14, 2017, the Company completed a private placement of 5.1 million equity units for gross proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to Warrants. Each equity unit consisted of 1 common share and 0.21 Warrants. Included in the issuance were 1.6 million common shares and 0.4 million Warrants issued to directors and officers of the Company or entities controlled by them, for proceeds of $2.9 million. In addition, 5.4 million Warrants valued at $0.8 million were issued in connection with the Term Loan. Each Warrant entitles the holder to acquire common shares on a one for one basis at an exercise price of $2.34 per share (the "Exercise Price") prior to March 14, 2020. If the volume weighted average price of Perpetual's common shares is greater than the Exercise Price for 60 consecutive calendar days, Perpetual has the option to require Warrant holders to exercise all or any portion of the Warrants at any time thereafter.

On November 17, 2016, the Company issued 0.5 million flow-through shares at a price of $2.15 per share for total gross cash proceeds of $1.1 million. The implied premium received in excess of the fair value of the common shares on the date of issue was $0.2 million or $0.44 per share and has been recorded in accounts payable and accrued liabilities pending the incurrence of qualified exploration expenditures by the Company. As at December 31, 2016 the Company was committed to spend $1.1 million on qualified exploration expenditures by December 31, 2017. The exploration expenditures have been incurred in 2017 and renounced to investors.

On January 18, 2016, Perpetual issued 33.3 million common shares of the Company upon closing of a fully backstopped rights offering to issue common shares of Perpetual for gross proceeds of $25 million. Included were 21.4 million common shares issued to entities controlled by the Chairman of Perpetual's Board of Directors for proceeds of $16.1 million.

As at December 31, 2017 and the date of this MD&A, there were 59.3 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)* | **February 22, 2018** |
|---|---|
| Share options | **4.0** |
| Restricted rights | – |
| Performance share rights(1) | **1.1** |
| Compensation awards | **4.1** |
| Warrants | **6.5** |
| Total | **15.7** |

(1) 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 December 31, 2017, performance multipliers of 2.0 and 1.0 have been assumed for those unvested awards granted in 2016 and 2017 respectively.

## CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2017, the Company's contractual obligations over the next five years and thereafter are as follows:

| **Contractual repayments of financial liabilities** *($ thousands)* | **2018** | **2019** | **2020** | **2021** | **2022 and Thereafter** | **Total** |
|---|---|---|---|---|---|---|
| Accounts payable and accrued liabilities | 31,410 | – | – | – | – | **31,410** |
| Fair value of derivatives | 7,885 | – | – | – | – | **7,885** |
| TOU share margin loans – principal | 18,490 | – | – | – | – | **18,490** |
| Revolving bank debt – principal | – | 31,826 | – | – | – | **31,826** |
| Term Loan – principal | – | – | – | 45,000 | – | **45,000** |
| Senior Notes – principal | – | 14,572 | – | – | 17,918 | **32,490** |
| Gas over bitumen royalty financing | 1,152 | 939 | 391 | 257 | – | **2,739** |
| Pipeline transportation commitments | 4,193 | 3,730 | 2,343 | 1,022 | 1,022 | **12,310** |
| Office and other operating lease commitments | 1,371 | 1,065 | 1,098 | 1,159 | 3,815 | **8,508** |
| Total | 64,501 | 52,132 | 3,832 | 47,438 | 22,755 | **190,658** |

### *Commodity price risk management*

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in cash flow from operating activities 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 rate forward contracts and physical or financial swaps 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.

Natural Gas

The following tables provide a summary of derivative natural gas contracts outstanding at February 22, 2018.

The Company has in place open physical and financial natural gas arrangements 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** |
|---|---|---|---|---|
| April 2018 – October 2018 | 10,000 | 2.06 | 1.16 | Financial |
| April 2018 – March 2019 | 10,000 | 1.41 | 1.43 | Financial |
| September 2018 – March 2019 | 5,000 | 1.40 | 1.68 | Physical |

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward AECO Monthly Index prices as of market close on February 22, 2018.

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

| **Term** | **Volumes sold (bought)** *(MMBTU/d)* | **AECO-NYMEX differential** *(US$/MMBTU)* | **Market prices** *(US$/MMBTU)*(1) | **Type of contract** |
|---|---|---|---|---|
| April 2018 – October 2018 | 7,500 | (1.80) | (1.77) | Financial |
| January 2019 – December 2019 | 20,000 | (1.52) | (1.48) | Financial |
| January 2020 – December 2020 | 10,000 | (1.41) | (1.36) | Financial |

(1) Market prices are based on forward AECO-NYMEX differential prices as of market close on February 22, 2018.

Crude Oil

The Corporation 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 |
|---|---|---|---|---|---|
| February 2018 – December 2018 | 250 | 50.00 | 58.40 | 60.72 | Financial |
| February 2018 – December 2018 | 250 | 50.00 | 60.00 | 60.72 | Financial |

(1) Market prices are based on forward WTI oil prices as of market close on February 22, 2018.

| Term | Volumes at WTI (*bbl/d*) | Average price (*US$*/bbl) | Market prices (*US$*/bbl)[1] | Type of contract |
|---|---|---|---|---|
| February 2018 – December 2018 | 250 | 63.74 | 60.72 | Fixed Price |

(1) Average price calculated using weighted average price for net open contracts.

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 |
|---|---|---|---|---|
| April 2018 – June 2018 | 500 | (14.45) | (24.55) | 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 are based on forward WTI-WCS differential prices as of market close on February 22, 2018.

## SUMMARY OF QUARTERLY RESULTS

| *($ thousands, except where noted)* | **Q4 2017** | Q3 2017 | Q2 2017 | Q1 2017 |
|---|---|---|---|---|
| **Financial** | | | | |
| Oil and natural gas revenue | **23,810** | 20,026 | 19,728 | 18,158 |
| Net loss | **(6,498)** | (8,082) | (7,219) | (14,172) |
| Per share – basic | **(0.11)** | (0.14) | (0.12) | (0.26) |
| Per share – diluted | **(0.11)** | (0.14) | (0.12) | (0.26) |
| Cash flow from (used in) operating activities | **10,953** | 5,778 | 4,728 | (2,289) |
| Adjusted funds flow[1] | **12,541** | 8,199 | 5,243 | 5,110 |
| Per share – basic | **0.21** | 0.14 | 0.09 | 0.09 |
| Net capital expenditures | | | | |
| Capital expenditures | **19,047** | 25,392 | 4,006 | 24,590 |
| Geological and geophysical costs | **–** | – | (22) | – |
| Net payments on acquisitions and dispositions | **970** | 680 | 609 | 163 |
| Net capital expenditures | **20,017** | 26,072 | 4,593 | 24,753 |
| **Common shares** *(thousands)* | | | | |
| Weighted average – basic | **59,338** | 59,152 | 59,045 | 54,468 |
| Weighted average – diluted | **59,338** | 59,152 | 59,045 | 54,468 |
| **Operating** | | | | |
| Daily average production | | | | |
| Natural gas *(MMcf/d)* | **60.8** | 51.8 | 45.1 | 40.7 |
| Oil *(bbl/d)* | **888** | 978 | 1,049 | 877 |
| NGL *(bbl/d)* | **738** | 733 | 665 | 479 |
| Total *(boe/d)* | **11,765** | 10,330 | 9,223 | 8,143 |
| Average prices | | | | |
| Realized natural gas price *($/Mcf)*[2] | **3.22** | 3.11 | 3.18 | 5.04 |
| Realized oil price *($/bbl)*[2] | **47.30** | 43.01 | 43.91 | 31.39 |
| NGL price *($/bbl)* | **54.17** | 39.06 | 44.28 | 49.70 |

(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. Realized gains and losses from foreign exchange contracts are excluded.

| *($ thousands, except where noted)* | Q4 2016 | Q3 2016 | Q2 2016 | Q1 2016 |
|---|---|---|---|---|
| **Financial** | | | | |
| Oil and natural gas revenue | 17,940 | 22,268 | 16,501 | 24,694 |
| Net income (loss) | 20,379 | (10,919) | 64,925 | 32,764 |
| Per share – basic | 0.39 | (0.21) | 1.25 | 0.72 |
| Per share – diluted | 0.37 | (0.21) | 1.23 | 0.70 |
| Cash flow from (used in) operating activities | 4,740 | (1,710) | (3,396) | (6,770) |
| Adjusted funds flow[1] | 3,326 | (602) | (1,852) | 48 |
| Per share – basic | 0.06 | (0.01) | (0.04) | 0.00 |
| Net capital expenditures | | | | |
| Capital expenditures | 7,069 | 1,411 | 1,286 | 4,814 |
| Geological and geophysical costs | (3) | – | 11 | 15 |
| Net payments (proceeds) on acquisitions and dispositions | 1,785 | (988) | (302) | (6,466) |
| Net capital expenditures | 8,851 | 423 | 995 | (1,637) |
| **Common shares** *(thousands)*[2] | | | | |
| Weighted average – basic | 52,924 | 52,253 | 52,140 | 45,573 |
| Weighted average – diluted | 54,678 | 52,253 | 52,904 | 47,022 |
| **Operating** | | | | |
| Daily average production | | | | |
| Natural gas *(MMcf/d)* | 40.3 | 75.5 | 85.2 | 98.2 |
| Oil *(bbl/d)* | 936 | 1,052 | 1,073 | 1,174 |
| NGL *(bbl/d)* | 467 | 476 | 682 | 836 |
| Total *(boe/d)* | 8,118 | 14,123 | 15,959 | 18,378 |
| Average prices | | | | |
| Realized natural gas price *($/Mcf)*[3] | 2.41 | 2.12 | 1.85 | 3.15 |
| Realized oil price *($/bbl)*[3] | 38.95 | 38.90 | 39.17 | 33.90 |
| NGL price *($/bbl)* | 46.99 | 35.80 | 34.71 | 29.33 |

(1) See "Non-GAAP measures" in this MD&A.
(2) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. All common shares are presented net of shares held in trust.
(3) 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. Realized gains and losses from foreign exchange contracts are excluded.

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 declined 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 Properties. Capital expenditures increased significantly in 2017, resulting in increasing production, revenues and adjusted funds flow as the year progressed. Capital expenditures are typically low during the second quarter when break-up conditions reduce access for field activities.

## SELECTED ANNUAL INFORMATION

| *($ thousands, except where noted)* | **2017** | 2016 | 2015 |
|---|---|---|---|
| **Financial** | | | |
| Oil and natural gas revenue | **81,722** | 81,403 | 142,437 |
| Net income (loss) | **(35,971)** | 107,149 | (89,274) |
| Per share – basic[1] | **(0.62)** | 2.11 | (11.89) |
| Per share – diluted[1] | **(0.62)** | 1.98 | (11.89) |
| Cash flow from (used in) operating activities | **19,170** | (7,136) | 12,406 |
| Adjusted funds flow | **31,093** | 920 | 2,004 |
| Per share[1][2] | **0.54** | 0.02 | 0.26 |
| Total assets | **365,570** | 361,405 | 603,450 |
| Total long-term liabilities | **144,186** | 97,215 | 443,648 |
| Revolving bank debt | **31,581** | – | – |
| Senior Notes, at principal amount | **32,490** | 60,573 | 275,000 |
| Term Loan, at principal amount | **45,000** | – | – |
| TOU share margin loans, at principal amount | **18,490** | 39,953 | 60,059 |
| Carrying amount of TOU share investment | **(37,985)** | (66,343) | (145,275) |
| Net working capital deficiency | **16,404** | 3,917 | 13,832 |
| Total net debt | **105,980** | 38,100 | 203,616 |
| Net capital expenditures | | | |
| Capital expenditures | **73,035** | 14,580 | 76,341 |
| Geological and geophysical costs | **(22)** | 23 | 1,526 |
| Net payments (proceeds) on acquisitions and dispositions | **2,422** | (5,972) | (23,710) |
| Net capital expenditures | **75,435** | 8,631 | 54,157 |
| **Common shares** (*thousands*)[3] | | | |
| End of period[4] | **59,263** | 53,421 | 19,067 |
| Weighted average – basic | **58,017** | 50,733 | 7,507 |
| Weighted average – diluted | **58,017** | 54,038 | 7,507 |
| **Operating** | | | |
| Daily average production | | | |
| Natural gas (*MMcf/d*) | **49.6** | 74.7 | 104.2 |
| Oil (*bbl/d*) | **948** | 1,058 | 1,626 |
| NGL (*bbl/d*) | **655** | 614 | 711 |
| Total average production (*boe/d*) | **9,876** | 14,128 | 19,706 |
| Average prices | | | |
| Realized natural gas price *($/Mcf)* | **3.51** | 2.42 | 3.01 |
| Realized oil price *($/bbl)* | **41.62** | 37.60 | 52.48 |
| NGL price (*$/bbl*) | **46.60** | 35.45 | 33.72 |
| Wells drilled | | | |
| Natural gas – gross (net) | **15 (14.4)** | 4 (4.0) | 6 (4.5) |
| Crude oil – gross (net) | **4 (3.3)** | – (–) | – (–) |
| Total – gross (net) | **19 (17.7)** | 4 (4.0) | 6 (4.5) |

(1) Based on weighted average common shares outstanding for the year.
(2) See "non-GAAP measure" in this MD&A.
(3) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. Common shares are presented net of shares held in trust.
(4) Reduced by shares held in trust (2017 – 447; 2016 – 260; and 2015 – 47). See "Note 15 to the Audited Consolidated Financial Statements".

## OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

## FUTURE ACCOUNTING PRONOUNCEMENTS

The International Accounting Standards Board (IASB) and the IFRS Interpretations Committee regularly issue new and revised accounting pronouncements which have future effective dates and therefore are not reflected in Perpetual's financial statements. Once adopted these new and amended pronouncements may have an impact on Perpetual's consolidated financial statements. Perpetual's analysis of recent accounting pronouncements is included in the notes to the consolidated financial statements at December 31, 2017 (note 3n).

## CORPORATE GOVERNANCE

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

## RISK FACTORS

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

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

Perpetual manages these risks by:

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

A complete discussion of risk factors is included in the Corporation's 2017 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

## DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

### Disclosure controls and procedures

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

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2017, the DC&P are effective to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

### Management's annual report on internal controls over financial reporting

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

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2017 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2017, the internal control over financial reporting was effective.

### Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the period beginning on January 1, 2017 and ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

### CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2017 report filed with the Canadian securities regulators.

## CRITICAL ACCOUNTING ESTIMATES

Perpetual makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements. Critical accounting estimates include oil and natural gas reserves, derivative financial instruments, provisions, the amount and likelihood of contingent liabilities and income taxes. Critical accounting estimates are based on variable inputs including:

- Estimation of recoverable oil and natural gas reserves and future cash flows from reserves;
- Forward market prices;
- Geological interpretations, success or failure of exploration activities, and Perpetual's plans with respect to property and financial ability to hold the property;
- Risk free interest rates;
- Estimation of future abandonment and reclamation costs;
- Facts and circumstances supporting the likelihood and amount of contingent liabilities; and
- Interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net income as a result of their impact on the depletion rate, provisions, impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2017.

**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, natural gas liquids ("NGL") and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and financial contracts to be employed, and the value of financial forward natural gas, oil and other risk management contracts; net income and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; 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 covenants in 2018 and 2019; the retention of, and benefits to be received from holding the TOU shares (as defined above); 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. 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.

**OIL AND GAS ADVISORIES**

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

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

F&D recycle ratio is calculated by dividing the operating netback for the period by the F&D costs per boe for the particular reserve category.

# CONSOLIDATED FINANCIAL STATEMENTS

## MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("the Company") are the responsibility of Management and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by Management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the Interpretations of the IFRS Interpretations Committee.

The consolidated financial statements are audited and have been prepared using accounting policies in accordance with IFRS. The preparation of Management's Discussion and Analysis is based on the Company's financial results which have been prepared in accordance with IFRS. It compares the Company's financial performance in 2017 to 2016 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management believes that the system of internal controls that have been designed and maintained at the Company provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, financial performance and cash flows in accordance with IFRS. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

| | |
|---|---|
| **Susan L. Riddell Rose**<br>President &<br>Chief Executive Officer | **W. Mark Schweitzer**<br>Vice President, Finance &<br>Chief Financial Officer |

February 22, 2018

## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Perpetual Energy Inc.

We have audited the accompanying consolidated financial statements of Perpetual Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Perpetual Energy Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 22, 2018

## PERPETUAL ENERGY INC.
## Consolidated Statements of Financial Position

| As at | | December 31, 2017 | | December 31, 2016 |
|---|---|---|---|---|
| (*Cdn$ thousands*) | | | | |
| **Assets** | | | | |
| Current assets | | | | |
| Cash and cash equivalents | **$** | **–** | $ | 2,877 |
| Restricted cash (note 9) | | **–** | | 2,000 |
| Accounts receivable (note 19) | | **14,069** | | 11,473 |
| Tourmaline Oil Corp. ("TOU") share investment (note 4) | | **37,985** | | 66,343 |
| Prepaid expenses and deposits | | **937** | | 990 |
| Fair value of derivatives (note 19) | | **1,585** | | 8,326 |
| | | **54,576** | | 92,009 |
| Fair value of derivatives (note 19) | | **1,506** | | 2,351 |
| Property, plant and equipment (note 5) | | **262,784** | | 219,886 |
| Exploration and evaluation (note 6) | | **46,704** | | 47,159 |
| Total assets | **$** | **365,570** | $ | 361,405 |
| **Liabilities** | | | | |
| Current liabilities | | | | |
| Accounts payable and accrued liabilities | **$** | **31,410** | $ | 21,257 |
| Fair value of derivatives (note 19) | | **7,885** | | 9,221 |
| TOU share margin loans (note 8) | | **18,406** | | 39,953 |
| Gas over bitumen royalty financing (note 12) | | **1,152** | | 3,390 |
| Provisions (note 13) | | **2,580** | | 7,656 |
| | | **61,433** | | 81,477 |
| Fair value of derivatives (note 19) | | **–** | | 2,023 |
| Revolving bank debt (note 9) | | **31,581** | | – |
| Term loan (note 10) | | **43,233** | | – |
| Senior notes (note 11) | | **31,680** | | 60,120 |
| Gas over bitumen royalty financing (note 12) | | **1,587** | | 4,954 |
| Provisions (note 13) | | **36,105** | | 30,118 |
| Total liabilities | | **205,619** | | 178,692 |
| **Equity** | | | | |
| Share capital (note 15) | | **1,336,838** | | 1,325,705 |
| Warrants (note 15) | | **923** | | – |
| Contributed surplus | | **44,152** | | 42,999 |
| Deficit | | **(1,221,962)** | | (1,185,991) |
| Total equity | | **159,951** | | 182,713 |
| Total liabilities and equity | **$** | **365,570** | $ | 361,405 |

Commitments (note 14).

See accompanying notes to the consolidated financial statements.

**Robert A. Maitland**
Director

**Geoffrey C. Merritt**
Director

## PERPETUAL ENERGY INC.
## Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

| For the year ended | December 31, 2017 | December 31 2016 |
|---|---|---|
| (*Cdn$ thousands, except per share amounts*) | | |
| Revenue | | |
| Oil and natural gas | **$ 81,722** | $ 81,403 |
| Royalties | **(11,973)** | (9,415) |
| | **69,749** | 71,988 |
| Change in fair value of derivatives (note 19) | **5,855** | 18,041 |
| Gas over bitumen royalty credit and other | **2,460** | 1,984 |
| | **78,064** | 92,013 |
| Expenses | | |
| Production and operating | **16,299** | 35,019 |
| Transportation | **5,051** | 7,925 |
| Exploration and evaluation (note 6) | **3,283** | 3,790 |
| General and administrative | **11,943** | 17,153 |
| Share-based payments (note 6) | **4,310** | 5,911 |
| Depletion and depreciation (note 5) | **33,436** | 54,317 |
| Loss (gain) on dispositions (notes 5a and 6) | **8,775** | (27,770) |
| Restructuring (note 13b) | **–** | 5,638 |
| Impairment reversal (note 5c) | **–** | (6,900) |
| **Loss from operating activities** | **(5,033)** | (3,070) |
| Finance expenses (note 17) | **(7,592)** | (24,847) |
| Change in fair value of TOU share investment (note 4) | **(22,671)** | 58,897 |
| Gain on exchange of senior notes for TOU share investment (note 11) | **–** | 81,310 |
| Loss on disposition of gas storage facility investment (note 5b) | **(675)** | (6,165) |
| Share of net income of gas storage facility investment (note 5b) | **–** | 1,024 |
| **Net income (loss) and comprehensive income (loss)** | **(35,971)** | 107,149 |
| **Income (loss) per share (note 15)** | | |
| Basic | **$ (0.62)** | $ 2.11 |
| Diluted | **$ (0.62)** | $ 1.98 |

See accompanying notes to the consolidated financial statements.

## PERPETUAL ENERGY INC.
## Consolidated Statements of Changes in Equity

| | Share capital (thousands) | Share capital ($thousands) | Warrants | Contributed surplus | Deficit | Total equity |
|---|---|---|---|---|---|---|
| *(Cdn$ thousands, except share amounts)* | | | | | | |
| Balance at December 31, 2016 | 53,421 | $ 1,325,705 | $ – | $ 42,999 | $ (1,185,991) | $ 182,713 |
| Net income | – | – | – | – | (35,971) | (35,971) |
| Common shares and warrants issued (note 15) | 6,030 | 10,696 | 923 | (1,720) | – | 9,899 |
| Change in shares held in trust (note 15) | (188) | 437 | – | (1,437) | – | (1,000) |
| Share-based payments (note 16) | – | – | – | 4,310 | – | 4,310 |
| **Balance at December 31, 2017** | **59,263** | **$ 1,336,838** | **$923** | **$ 44,152** | **$ (1,221,962)** | **$ 159,951** |

| | Share capital (thousands) | Share capital ($thousands) | Share Purchase Rights | Contributed surplus | Deficit | Total equity |
|---|---|---|---|---|---|---|
| *(Cdn$ thousands, except share amounts)* | | | | | | |
| Balance at December 31, 2015 | 19,068 | $ 1,296,734 | $ 5,290 | $ 38,300 | $ (1,293,140) | $ 47,184 |
| Net income | – | – | – | – | 107,149 | 107,149 |
| Common shares issued (note 15) | 34,566 | 28,943 | (5,290) | (1,184) | – | 22,469 |
| Change in shares held in trust (note 15) | (213) | 28 | – | (28) | – | – |
| Share-based payments (note 16) | – | – | – | 5,911 | – | 5,911 |
| Balance at December 31, 2016 | 53,421 | $ 1,325,705 | $ – | $ 42,999 | $ (1,185,991) | $ 182,713 |

See accompanying notes to the consolidated financial statements.

## PERPETUAL ENERGY INC.
## Consolidated Statements of Cash Flows

| For the year ended | December 31, 2017 | December 31, 2016 |
|---|---|---|
| (*Cdn$ thousands*) | | |
| **Cash flows from (used in) operating activities** | | |
| Net income (loss) | **$ (35,971)** | $ 107,149 |
| Adjustments to add (deduct) non-cash items: | | |
| Unrealized change in fair value of derivatives (note 19) | **(2,550)** | (13,340) |
| Exploration and evaluation (note 6) | **2,602** | 2,727 |
| Share based payments (note 16) | **4,310** | 5,911 |
| Depletion and depreciation (note 5) | **33,436** | 54,317 |
| Loss (gains) on dispositions (note 5a) | **8,775** | (27,770) |
| Restructuring costs (note 13) | **–** | 5,638 |
| Impairment reversal (note 5) | **–** | (6,900) |
| Finance expenses (income) (note 17) | **(412)** | 10,156 |
| Change in fair value of TOU share investment (note 4) | **22,671** | (58,897) |
| Gain on exchange of senior notes for TOU shares (note 11) | **–** | (81,572) |
| Loss on disposition of gas storage facility investment (note 5b) | **675** | 6,165 |
| Share of net income from gas storage facility investment (note 5b) | **–** | (1,024) |
| Dividends from gas storage facility investment | **–** | 501 |
| Expenditures on decommissioning obligations (note 13a) | **(2,336)** | (3,803) |
| Payments of restructuring costs (note 13b) | **(2,550)** | (1,484) |
| Change in non-cash working capital (note 18) | **(9,480)** | (4,910) |
| Net cash flows from (used in) operating activities | **19,170** | (7,136) |
| **Cash flows from (used in) financing activities** | | |
| Change in revolving bank debt, net of issue costs (note 9) | **31,523** | – |
| Change in TOU share margin loans, net of issue costs (note 8) | **(22,983)** | (26,613) |
| Change in term loan, net of issue costs (note 10) | **43,639** | – |
| Change in senior notes, net of issue costs (note 11) | **(28,580)** | – |
| Change in gas over bitumen royalty financing (note 12) | **(2,421)** | (2,164) |
| Common shares and warrants issued (note 15) | **9,130** | 22,631 |
| Shares purchased and held in trust (note 15) | **(1,000)** | (162) |
| Change in non-cash working capital (note 18) | **(216)** | 216 |
| Net cash flows from (used in) financing activities | **29,092** | (6,092) |
| **Cash flows from (used in) investing activities** | | |
| Capital expenditures | **(73,035)** | (14,580) |
| Acquisitions | **(432)** | (12) |
| Net proceeds (payments) on dispositions (note 5a) | **(1,990)** | 5,984 |
| Net proceeds (payments) on sale of gas storage facility investment (note 5b) | **(675)** | 19,703 |
| Proceeds on sale of TOU share investment (note 4) | **5,687** | 7,354 |
| Restricted cash | **2,000** | (2,000) |
| Change in non-cash working capital (note 18) | **17,306** | (2,460) |
| Net cash flows from (used in) investing activities | **(51,139)** | 13,989 |
| Change in cash and cash equivalents | **(2,877)** | 761 |
| Cash and cash equivalents, beginning of year | **2,877** | 2,116 |
| Cash and cash equivalents, end of year | **$ –** | $ 2,877 |

See accompanying notes to the consolidated financial statements.

## 1. REPORTING ENTITY

Perpetual Energy Inc. ("Perpetual" or the "Company") is a Canadian corporation engaged in the exploration, development and marketing of oil and natural gas based energy in Alberta, Canada. The Company operates a diversified asset portfolio that includes liquids-rich natural gas, shallow natural gas and conventional heavy oil producing properties, as well as undeveloped bitumen resource properties.

The address of the Company's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The consolidated financial statements of the Company are comprised of the accounts of Perpetual Energy Inc. and its wholly owned subsidiaries: Perpetual Operating Corp. and Perpetual Operating Trust, which are incorporated in Canada.

## 2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements of the Company were approved and authorized for issue by the Board of Directors on February 22, 2018.

The consolidated financial statements have been prepared on a historical cost basis except for the TOU share investment (note 4), TOU share margin loans (note 8), gas over bitumen royalty financing (note 12) and derivative financial instruments (note 19) that have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company and its subsidiaries.

### a) Critical accounting judgments and significant estimates

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenue and expenses. These judgments, estimates, and assumptions are continuously evaluated and are based on management's experience and all relevant information available to the Company at the time of financial statement preparation. As the effect of future events cannot be determined with certainty, the actual results may differ from estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about the critical judgments and significant estimates made by management are described below and in the relevant notes to the financial statements.

### b) Critical accounting judgments:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies. These judgments have the most significant effect on the amounts reported in the consolidated financial statements.

i) Cash-generating units ("CGUs")

The Company allocates its oil and natural gas properties to CGUs, identified as the smallest group of assets that generate cash inflows independent of the cash inflows of other assets or groups of assets. Determination of the CGUs is subject to management's judgement and is based on geographical proximity, shared infrastructure, and similar exposure to market risk.

ii) Identification of impairment indicators

Judgment is required to assess when indicators of impairment or reversals exist and whether calculation of the recoverable amount of an asset is necessary. Management considers internal and external sources of information including petroleum and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of previously impaired asset, whether the carrying amount of the asset has been restored.

iii) Componentization

For the purposes of depletion, the Company allocates its oil and natural assets to components with similar useful lives and depletion methods. The grouping of assets is subject to management's judgment and is performed on the basis of geographical proximity and similar reserve life. The Company's oil and gas assets are depleted on a unit-of-production basis.

iv) Exploration and evaluation expenditures

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as exploration and evaluation ("E&E") assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgment and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to confirm continued intent to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within property, plant and equipment referred to as oil and natural gas properties.

v) Joint arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, the Company considers whether unanimous consent is required to direct the activities that significantly affect the returns of the arrangement, such as the capital and operating activities of the arrangement.

Once joint control has been established, judgment is also required to classify a joint arrangement. The type of joint arrangement is determined through analysis of the rights and obligations arising from the arrangement by considering its structure, legal form, and terms agreed upon by the parties sharing control. An arrangement where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, is classified as a joint operation. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures.

vi) Deferred taxes

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and judgment as to whether there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

**c) Significant estimates:**

The following assumptions represent the key sources of estimation uncertainty at the end of the reporting period. As future confirming events occur the actual results may differ from estimated amounts.

i) Reserves

The Company uses estimates of natural gas, oil, and natural gas liquids ("NGL" or "liquids") reserves in the calculation of depletion and also for value in use ("VIU") and fair value less costs of disposal ("FVLCD") calculations of non-financial assets. Estimates of economically recoverable natural gas, oil, and NGL reserves and their future net cash flows are based upon a number of variable factors and assumptions, such as geological, geophysical, and engineering assessments of hydrocarbons in place on the Company's lands, historical production from the properties, production rates, future commodity prices, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by government agencies and future operating costs. The geological, economic and technical factors used to estimate reserves may change from period to period. Changes in the reported reserves could have a material impact on the carrying values of the Company's oil and natural gas properties, the calculation of depletion and depreciation and the timing of decommissioning expenditures.

Reserve engineers are engaged at least annually to independently evaluate or review the recoverable quantities and estimated future cash flows from the Company's interest in petroleum and natural gas properties. This evaluation of proved and proved plus probable reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

ii) Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for production facilities, wells and pipelines are expected to be incurred by the Company over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

iii) Derivative financial instruments

Derivatives are measured at fair value on each reporting date. Fair value is the price that would be received or paid to exit the position as of the measurement date. The Company uses estimated external forward market price curves available at period end and the contracted volumes over the contracted term to determine the fair value of each contract. Changes in market pricing between period end and settlement of the derivative contracts could have a material impact on financial results related to the derivatives.

iv) Gas over bitumen royalty financing

The gas over bitumen royalty financing is measured at fair value on each reporting date. Fair value is the price that would be paid to exit the position as of the measurement date.

The fair value of the gas over bitumen royalty financing is estimated by discounting future cash payments based on the forecasted Alberta gas reference price multiplied by the contracted deemed volume. Changes in market pricing between period end and settlement could have a material impact on financial results related to the gas over bitumen royalty financing.

v) TOU share put option margin loans

The fair value of the TOU share put option margin loans are estimated using market pricing for identical financial instruments adjusted for provisions specific to the contract such as the maximum repayment amount and the notional amount of shares pledged as security. Changes in the market pricing of the shares could have a material impact on the valuation of TOU share put option margin loans. The TOU share put option margin loans were repaid in full during the third quarter of 2017 (note 8).

vi) Share-based payments

Share options issued by the Company are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of share options, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these annual consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

### a) Basis of consolidation

i) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are considered. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued, and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired, and liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets acquired and liabilities assumed is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss.

iii) Joint venture

The Company's investment in Warwick Gas Storage Limited Partnership ("WGS LP") was structured through a separate vehicle whereby joint control was established and the contractual arrangement provided the parties with rights to the net assets of WGS LP. The Company's investment in WGS LP was accounted for as an investment in a jointly controlled entity using the equity-method of accounting. The investment in WGS LP was sold during the second quarter of 2016 (note 5b).

On initial recognition of the investment, any excess of the Company's share of the fair value of WGS LP's net assets over the cost of the investment was included in the determination of the Company's share of WGS LP's profit or losses. The Company's share of WGS LP's profits or losses were recognized in net income or loss. Appropriate adjustments to the Company's share of WGS LP profits or losses were also made to account for depreciation of assets based on their fair values at the date of initial recognition. Dividends receivable were recognized as a reduction to the carrying amount of the investment and were included in cash flows from operating activities.

An impairment loss in respect of an equity-method accounted investee is measured by comparing the recoverable amount of the investment with its carrying amount. An impairment loss is recognized in profit or loss, and is reversed if there is a favorable change in the estimates used to determine the recoverable amount.

iv) Jointly owned assets

Many of the Company's oil and natural gas activities involve jointly owned assets which are not conducted through a separate vehicle. The consolidated financial statements include the Company's proportionate share of these jointly owned assets, liabilities, revenues and expenses.

v) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

## b) Financial instruments

Financial instruments are initially recognized at fair value on the statement of financial position. Subsequent measurement of financial instruments is based on their initial classification into one of the following categories: financial assets and liabilities measured at fair value through profit or loss, loans and receivables, held to maturity investments, available-for-sale financial assets, or other financial liabilities.

Financial instruments presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides or the legal right and intention for net settlement exists.

i) Financial assets

| Financial Instrument | Category | Subsequent Measurement |
|---|---|---|
| Accounts receivable | Loans and receivables | Amortized cost |
| TOU share investment | Financial assets | Fair value through profit or loss |

The Company's accounts receivable is initially recognized on the date they originate and are measured at amortized cost using the effective interest method, less any impairment losses.

The TOU share investment is a non-derivative financial instrument measured at fair value through profit or loss ("FVTPL") as the Company manages such investments and makes decisions based on their fair value in accordance with the Company's risk management or investment strategy.

ii) Financial liabilities

| Financial Instrument | Category | Subsequent Measurement |
|---|---|---|
| Accounts payable and accrued liabilities | Financial liabilities | Amortized cost |
| TOU share margin loan | Financial liabilities | Amortized cost |
| Revolving bank debt | Financial liabilities | Amortized cost |
| Term Loan | Financial liabilities | Amortized cost |
| Senior notes | Financial liabilities | Amortized cost |
| Gas over bitumen royalty financing | Financial liabilities | Fair value through profit or loss |

Accounts payable and accrued liabilities, TOU share margin loan, revolving bank debt, Term Loan and senior notes are recognized initially at fair value and are subsequently measured at amortized cost using the effective interest method. The gas over bitumen royalty financing is initially recognized at fair value and subsequent changes in fair value are recognized in profit or loss.

iii) Derivative assets and liabilities

The Company has entered into certain financial derivative contracts to manage the exposure to market risks from fluctuations in commodity prices and currency rates. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity and currency contracts to be economic hedges. As a result, all financial derivative contracts are designated as fair value through profit or loss and recorded as derivatives on the statement of financial position at fair value. Changes in the fair value of the commodity price and currency rate derivatives are recognized in net income or loss.

The Company has accounted for its forward physical delivery fixed-price sales contracts as derivative financial instruments. Accordingly, such forward physical delivery fixed-price sales contracts are designated as fair value through profit or loss and recorded as derivatives on the statement of financial position at fair value.

Transaction costs on derivatives are recognized in net income or loss when incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in net income or loss.

iv) Share capital and warrants

Incremental costs directly attributable to the issue of common shares, warrants and share options are recognized as a deduction from equity, net of any tax effects.

## c) Property, plant and equipment

i) Production and development costs

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The initial cost of property, plant and equipment includes the purchase price or construction costs, costs that are directly attributable to bringing the asset into commercial operations, the initial estimate of decommissioning costs, and borrowing costs for qualifying assets.

Significant parts of an item of property, plant and equipment, including oil and natural gas properties, that have different useful lives from the life of the area or facility in general, are accounted for as separate items.

Gains and losses on disposition of an item of property, plant and equipment, including oil and natural gas properties, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized in net income or loss. The carrying amount of any replaced or disposed item of property, plant and equipment is derecognized.

ii) Subsequent costs

Costs incurred after the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income or loss as incurred. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The costs of the day-to-day servicing of property, plant and equipment are recognized in net income or loss as incurred.

iii) Depletion and depreciation

The net carrying amount of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, considering estimated future development costs necessary to bring those reserves into production and future decommissioning costs. Future development and decommissioning costs are estimated considering the level of development required to produce the reserves. The future development cost estimates are reviewed by independent reserve engineers at least annually.

Costs associated with office furniture, information technology, and leasehold improvements are carried at cost and are depreciated on a straight-line basis over a period ranging from one to three years.

Depreciation methods, useful lives and residual values are reviewed at each period end date for all classes of property, plant, and equipment.

**d) Exploration and evaluation expenditures**

Pre-license costs, geological and geophysical costs and lease rentals of undeveloped properties are recognized in net income or loss as incurred.

E&E costs, consisting of the costs of acquiring oil and natural gas licenses, are capitalized initially as E&E assets according to the nature of the assets acquired. Costs associated with drilling exploratory wells in an undeveloped area are capitalized as E&E costs. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. When technical feasibility and commercial viability are determined, the relevant expenditure is transferred to property, plant and equipment as oil and natural gas properties, after impairment is assessed and any applicable impairment loss is recognized in net income or loss.

The Company's E&E assets consist of undeveloped land, exploratory drilling assets, and bitumen evaluation assets. Gains and losses on disposition of E&E assets are determined by comparing the proceeds from disposition with the carrying amount and are recognized in net income or loss.

**e) Assets held for sale**

Non-current assets, or disposal groups consisting of assets and liabilities ("disposal groups"), are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Assets and liabilities qualifying as held for sale must be available for immediate sale in their present condition subject to normal terms and conditions and their sale must be highly probable.

Non-current assets, or disposal groups, are measured at the lower of the carrying amount and fair value less costs of disposal, with impairments recognized in net income or loss. Non-current assets or disposal groups held for sale are presented in current assets and liabilities within the statement of financial position. Assets held for sale are not subject to depletion and depreciation.

**f) Impairment**

i) Financial assets

Financial assets are assessed at each period end date to determine whether there is any objective evidence that they are impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income or loss. An impairment loss is reversed when there is objective evidence that the value of the financial asset has been partially or fully restored. For financial assets measured at amortized cost, the reversal is recognized in net income or loss.

ii) Non-financial assets

The carrying amounts of the Company's non-financial assets, other than E&E assets, are reviewed at each period end date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas properties, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together at a CGU level. The recoverable amount of an asset or a CGU is determined based on the higher of its FVLCD and its VIU. FVLCD is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCD of oil and gas properties is generally determined as the net present value of estimated future cash flows expected to arise from the continued use of the CGU and its eventual disposition, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. In determining VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. VIU is generally determined by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

E&E assets are assessed for impairment both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and natural gas properties in property, plant and equipment. If a test is required as a result of triggering facts and circumstances, the Company considers whether the combined recoverable amount of oil and natural gas properties and E&E assets at the total company level is sufficient to cover the combined carrying value of E&E and oil and natural gas assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU, including the related decommissioning obligation, exceeds its estimated recoverable amount. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amount of assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in net income or loss.

In respect of other assets, impairment losses recognized in prior years are assessed at each period end date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

### g) Share-based payments

Awards granted under share-based payment plans and agreements are equity-settled and are measured at grant-date fair value. Fair values are determined by means of an option pricing model using the exercise price of the equity instrument granted, the share price at the grant date, the expected life of the grant based on the vesting date and expiry date, estimates of volatility and interest rates over its expected life. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

The costs of the equity-settled share-based payments are recognized within property, plant and equipment to the extent they are directly attributable, with a corresponding increase in contributed surplus over the vesting period. Upon exercise or settlement of an equity-based instrument, consideration received, and associated amounts previously recorded in contributed surplus are recorded to share capital.

### h) Shares held in trust

The Company has compensation awards as part of its share-based payment plans whereby employees may be entitled to receive shares of the Company purchased on the open market by a trustee controlled by the Company. Shares acquired and held by the trustee for the benefit of employees that have not yet been issued to employees are a separate category of equity that are presented net of common shares outstanding in share capital on the statement of financial position (note 15). The balance of shares held in trust represents the cumulative cost of shares held by the trustee. Upon the issuance of shares to the employee, the amount attributable to an employee is deducted from the balance of shares held in trust and removed from contributed surplus.

### i) Flow-through shares

Periodically, the Company finances a portion of its exploration and development activities through the issuance of flow through shares. Resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Flow-through shares issued are recorded in share capital at the fair value of common shares on the date of issue. The premium received on issuing flow-through shares is initially recorded as a deferred liability. As qualifying expenditures are incurred, the premium is reversed, and a deferred income tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the renunciation and the difference is recognized as a deferred income tax expense or recovery.

### j) Provisions

Provisions are recognized when the Company has a current legal or constructive obligation as a result of a past event, which can be reliably estimated, and will require the outflow of economic resources to settle the obligation. A non-current provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and liability specific risks.

i) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. A provision is recorded for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's estimate of expenditures required to settle the present obligation at the statement of financial position date and using a risk-free interest rate not adjusted for credit risk. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the risk-free rate. The accretion of the provision due to the passage of time is recognized in net income or loss whereas changes in the provision arising from changes in estimated cash flows or changes in the risk-free rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

ii) Restructuring provisions

Restructuring provisions are recognized when the Company has developed a detailed formal plan for restructuring and has announced the plan's main features to those affected by it. The measurement of a restructuring provision includes only the direct expenditures arising from the restructuring, which are those amounts that are not associated with the ongoing activities of the Company.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract.

A provision for employee downsizing costs is recognized when the Company has announced the restructuring plan to those affected by it, and can no longer withdraw the offer of those benefits. The provision is measured on initial recognition at the Company's best estimate of the expenditure required to settle the obligation.

### k) Revenue

Revenue and royalty expense from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters a third-party transmission pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

The Company's entitlement to gas over bitumen royalty adjustments under the Natural Gas Royalty Regulation (2004) with respect to foregone production (deemed production) from gas wells shut-in for the benefit of bitumen producers in the Athabasca oil sands area, is recognized as gas over bitumen revenue in the period that deemed production occurs, to the extent that they are expected to be recovered through gas Crown royalties otherwise payable.

### l) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net income or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the period end date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the period end date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each period end date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

### m) Income or loss per share amounts

Basic income or loss per share is calculated by dividing the net income or loss by the weighted average number of common shares outstanding during the period. For the dilutive net income or loss per share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income or loss.

Diluted income or loss per share is calculated giving effect to the potential dilution that would occur if outstanding warrants, share options, restricted rights, performance share units, or deferred compensation awards were exercised or converted into common shares. The weighted average number of diluted shares is calculated in accordance with the treasury stock method for warrants, share options, restricted rights and performance share units. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the average market price.

### n) Recent pronouncements issued

The Company will be required to adopt the following new standards and amendments as issued by the IASB. The Company has evaluated the impact on the consolidated financial statements as discussed below.

i) In April 2016, the IASB issued its final amendments to IFRS 15, "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Perpetual on January 1, 2018.

   The Company has completed the process of reviewing its various revenue streams and underlying contracts with customers to determine the impact and determined that there are no expected impacts to net income.

ii) In July 2014, the IASB completed the final elements of IFRS 9, "Financial Instruments". The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in OCI rather than the statement of income, unless this creates an accounting mismatch. In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. IFRS 9 also contains a new model to be used for hedge accounting. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied on a retrospective basis by Perpetual on January 1, 2018.

   Perpetual has evaluated the impact of the new standards under IFRS 9 and has concluded that there will be no significant impact to the classification and measurement of Perpetual's existing financial assets and liabilities. In addition, the expected credit loss model will not impact Perpetual, as counterparties for revenues where credit risks exist are with entities that are large, well established purchasers and Perpetual historically has not experienced any significant collection issues with its oil and natural gas marketing receivables which are normally collected on the 25th day of the month following sales. Finally, the Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9.

The Company is currently evaluating the impact on the consolidated financial statements as discussed below.

i) IFRS 16, "Leases" was issued in January 2016 and replaces IAS 17 "Leases". Under the new standard, a single recognition and measurement model for leases is introduced which would require the recognition of most leases with a term greater than twelve months on the statement of financial position. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. IFRS 16 will be applied by Perpetual on January 1, 2019.

## 4. TOU SHARE INVESTMENT

| | **December 31, 2017** | | December 31, 2016 | |
|---|---|---|---|---|
| | **Shares** *(thousands)* | **Amount** *($thousands)* | Shares *(thousands)* | Amount *($thousands)* |
| Balance, beginning of year | **$ 1,847** | **$ 66,343** | $ 6,500 | $ 145,275 |
| Sold | **(180)** | **(5,687)** | (250) | (7,354) |
| Unrealized change in fair value | **–** | **(22,671)** | – | 58,897 |
| Exchange for senior notes (note 11) | **–** | **–** | (4,403) | (130,475) |
| **Balance, end of year** | **$ 1,667** | **$ 37,985** | $ 1,847 | $ 66,343 |

TOU is engaged in the acquisition, exploration, development and production of petroleum and natural gas properties situated in western Canada. TOU shares are listed on the Toronto Stock Exchange under the trading symbol "TOU".

During the second quarter of 2016, 4.4 million TOU shares valued at $130.5 million were exchanged for the Company's senior notes (note 11).

At December 31, 2017, the Company held 1.67 million (December 31, 2016 – 1.85 million) TOU shares with a fair market value of $38.0 million (December 31, 2016 – $66.3 million) based on a December 31, 2017 closing price of $22.78 per share (December 31, 2016 – $35.91). Net income for the year ended December 31, 2017 includes an unrealized loss of $22.7 million (2016 – unrealized gain of $58.9 million) representing the change in fair value of TOU shares held during the year.

At December 31, 2017, 1.67 million TOU shares (December 31, 2016 – 1.5 million TOU shares) were pledged as security for the TOU share margin loan (note 8).

As at December 31, 2017, a $1.00 per share change in the market price of TOU shares would change the Company's after tax net income by $1.7 million.

## 5. PROPERTY, PLANT AND EQUIPMENT

| | Oil and Gas Properties | Corporate Assets | Total |
|---|---|---|---|
| **Cost** | | | |
| December 31, 2015 | $ 2,430,568 | $ 7,090 | $ 2,437,658 |
| Additions | 14,170 | 92 | 14,262 |
| Change in decommissioning obligations (note 13) | 5,213 | – | 5,213 |
| Dispositions | (1,838,905) | – | (1,838,905) |
| December 31, 2016 | 611,046 | 7,182 | 618,228 |
| Additions | 71,008 | 79 | 71,087 |
| Acquisitions | 233 | – | 233 |
| Change in decommissioning obligations (note 13) | 5,022 | – | 5,022 |
| Dispositions | (8) | – | (8) |
| **December 31, 2017** | **$ 687,301** | **$ 7,261** | **$ 694,562** |
| **Accumulated depletion, depreciation and impairment losses** | | | |
| December 31, 2015 | $ (2,083,135) | $ (6,620) | $ (2,089,755) |
| Depletion and depreciation | (54,034) | (283) | (54,317) |
| Dispositions | 1,738,830 | – | 1,738,830 |
| Impairment reversal | 6,900 | – | 6,900 |
| December 31, 2016 | (391,439) | (6,903) | (398,342) |
| Depletion and depreciation | (33,226) | (210) | (33,436) |
| **December 31, 2017** | **$ (424,665)** | **$ (7,113)** | **$ (431,778)** |
| **Carrying amount** | | | |
| December 31, 2016 | $ 219,607 | $ 279 | $ 219,886 |
| **December 31, 2017** | **$ 262,636** | **$ 148** | **$ 262,784** |

At December 31, 2017, property, plant and equipment included $1.3 million (December 31, 2016 – $1.4 million) of costs currently not subject to depletion.

For the year ended December 31, 2017, $2.3 million (December 31, 2016 – $0.5 million) of direct general and administrative expenses were capitalized. Future development costs for the year ended December 31, 2017 of $348.4 million (December 31, 2016 – $367.6 million) were included in the depletion calculation.

### a) Dispositions

*Proceeds on dispositions*

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Proceeds on dispositions of oil and gas properties | **$ 910** | $ 6,521 |
| Proceeds (payments) on retained shallow gas marketing arrangements | **869** | (87) |
| Payments on fixed portion of retained shallow gas marketing arrangements | **(3,769)** | (450) |
| Net proceeds (payments) on dispositions | **$ (1,990)** | $ 5,984 |

*Gain (loss) on dispositions*

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Proceeds on dispositions of oil and gas properties | **$ 910** | $ 6,521 |
| Proceeds (payments) on retained shallow gas marketing arrangements | **869** | (87) |
| Property, plant and equipment after net accumulated DD&A (note 5) | **(8)** | (100,075) |
| Exploration and evaluation (note 6) | **–** | (6,851) |
| Decommissioning obligations (note 13a) | **–** | 129,602 |
| Marketing arrangements related to shallow gas property disposition | **–** | (3,184) |
| Unrealized gain (loss) on retained shallow gas marketing arrangements | **(10,546)** | 1,844 |
| Gain (loss) on dispositions | **$ (8,775)** | $ 27,770 |

During the year ended December 31, 2017, the Company received net cash proceeds of $0.9 million (2016 – $6.5 million) related to the sale of certain gross overriding royalties and non-core undeveloped land.

On October 1, 2016, the Company disposed of a significant portion of the Company's shallow gas properties in east central and northeast Alberta (the "Shallow Gas Properties") for nominal cash consideration and the assumption of $128.0 million of decommissioning obligations associated with the Shallow Gas Properties, resulting in a gain on disposition of $19.2 million. In addition, the transaction included retained marketing arrangements whereby the Company provided 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.

On May 18, 2017, the Company amended the retained marketing arrangements whereby the $2.81/GJ ceiling price was reset to $3.50/GJ on 10,000 GJ/d for the periods between November 1, 2017 and March 31, 2018 in exchange for proceeds of $0.3 million.

As at December 31, 2017, the net retained shallow gas marketing arrangements have been summarized as follows:

| **Term** | **Volumes at AECO** (*GJ/d*) | **Floor price** (*$/GJ*) | **Ceiling price** (*$/GJ*) | **Fair value** (*$ thousands*) |
|---|---|---|---|---|
| January 2018 – August 2018 | 33,611 | – | 2.81 | – |
| January 2018 – March 2018 | (10,000) | – | (2.81) | – |
| January 2018 – March 2018 | 10,000 | – | 3.50 | – |
| January 2018 – March 2018(1) | 33,611 | 2.58 | – | (929) |
| April 2018 – August 2018 | 33,611 | 2.58 | – | (6,736) |
| Total net retained shallow gas marketing arrangements (note 19(c)(i)) | | | | (7,665) |

(1) At December 31, 2017 the cost of the put option between the periods of January 1, 2018 and March 31, 2018 was fixed at $0.9 million which settles monthly over the remaining term and is recorded at amortized cost (note 19(c)(i)).

Realized and unrealized gains and losses on these marketing arrangements are recognized as adjustments to gains and losses on dispositions and included as cash flows from investing activities on the consolidated statement of cash flows. Subsequent to December 31, 2017, the Company has fixed the cost of net retained shallow gas obligations at $8.5 million to be paid over the remaining January to August 2018 marketing arrangement period.

### b) Loss on disposition of gas storage facility investment

The Company owned a 30% partnership interest in the WGS LP gas storage facility located in Alberta, Canada that was accounted for using the equity-method.

On May 25, 2016, the Company disposed of its interest in WGS LP for net cash proceeds of $19.7 million, resulting in a net loss on disposition of $6.2 million.

Prior to the disposition, transactions between the Company and WGS LP totaled $0.6 million in 2016, consisting primarily of fees earned for the provision of management and operational services. This service agreement between the Company and WGS LP was terminated concurrent with the disposition. The Company received dividends of $0.5 million which were declared and received by WGS LP prior to the disposition.

Summary financial information for the Company's equity method gas storage facility investment is as follows:

| For the period ended | May 25, 2016 |
|---|---|
| Revenue | $ 6,756 |
| Depreciation | (1,398) |
| Other expenses | (2,511) |
| Unrealized gain (loss) on gas storage obligation derivative | 623 |
| Net income (loss) | 3,470 |
| Share of net income (loss) | 1,041 |
| Amortization of fair value adjustment on acquisition of interest in WGS LP | (17) |
| Share of net income (loss) of equity method investment | $ 1,024 |

In 2017, the Company recorded a negative adjustment to the disposition of the gas storage facility of $0.7 million.

### c) Cash-generating units, impairments and reversals

For the year ended December 31, 2017, the Company assessed impairment indicators for the Company's CGUs. There was no impairment or impairment reversal recognized in 2017.

For the year ended December 31, 2016, the Company assessed impairment indicators for the Company's CGUs. In performing the review, management determined that the disposition of the Shallow Gas Properties justified calculation of the recoverable amount of the Northern CGU. In addition, technical revisions to Mannville heavy oil reserves related to improved recovery methods along with realized lower operating and capital efficiencies justified a review for impairment reversals for the Eastern CGU. The Company determined the recoverable amount of Northern and Eastern CGUs using VIU based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators along with the associated year-end commodity price forecast, and an estimate of market discount rates between 12 and 20 percent to consider risks specific to the asset.

At December 31, 2016, the Company recorded a net impairment reversal of $6.9 million to net income which was comprised of the following:

- The Company determined that the carrying amount of the Northern CGU of $6.7 million exceeded the recoverable amounts. Accordingly, an impairment charge of $5.8 million was included in net income reducing the carrying amount to $0.9 million; and
- The Company determined that the recoverable amount of the Eastern CGU exceeded its carrying amount of $33.1 million by $15.9 million; accordingly, a reversal of $12.7 million was recognized in net income representing the full reversal of previously recorded impairments adjusted for depletion resulting in a carrying amount $45.8 million.

The independent reserves evaluator's commodity price estimates were used in the VIU calculations as at December 31, 2016:

| Year | WTI Crude Oil (*US$/bbl*) | USD/CDN exchange rate (*US$/Cdn$*) | Alberta heavy crude oil (*Cdn$/bbl*) | AECO natural gas (*Cdn$/mmbtu*) |
|---|---|---|---|---|
| 2017 | 55.00 | 0.75 | 46.50 | 3.40 |
| 2018 | 58.70 | 0.78 | 50.50 | 3.15 |
| 2019 | 62.40 | 0.80 | 54.00 | 3.30 |
| 2020 | 69.00 | 0.83 | 58.00 | 3.60 |
| 2021 | 75.80 | 0.85 | 61.90 | 3.90 |
| 2022 | 77.30 | 0.85 | 63.10 | 3.95 |
| 2023 | 78.80 | 0.85 | 64.40 | 4.10 |
| 2024 | 80.40 | 0.85 | 65.60 | 4.25 |
| 2025 | 82.00 | 0.85 | 67.00 | 4.30 |
| 2026 | 83.70 | 0.85 | 68.40 | 4.40 |
| 2027 | 85.30 | 0.85 | 69.60 | 4.50 |
| 2028 | 87.00 | 0.85 | 71.10 | 4.60 |
| 2029 | 88.80 | 0.85 | 72.50 | 4.65 |
| 2030 | 90.60 | 0.85 | 74.00 | 4.75 |
| 2031 | 92.40 | 0.85 | 75.40 | 4.85 |

Escalate 2.0% per year thereafter

## 6. EXPLORATION AND EVALUATION

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Balance, beginning of year | **$ 47,159** | $ 56,407 |
| Additions | **1,948** | 318 |
| Acquisitions | **199** | 12 |
| Dispositions | **–** | (6,851) |
| Non-cash exploration and evaluation expense | **(2,602)** | (2,727) |
| Transfers to property, plant and equipment | **–** | – |
| Balance, end of year | **$ 46,704** | $ 47,159 |

During the year ended December 31, 2017, $0.7 million (2016 – $1.1 million) in costs were charged directly to E&E expense in net income (loss).

## 7. CAPITAL MANAGEMENT

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 and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, revolving bank debt, the Term Loan, TOU share margin loans and net working capital, with value and liquidity enhanced through the current ownership of TOU shares. In order 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.

During the year ended December 31, 2017, the Company completed several financing transactions to strengthen Perpetual's liquidity and debt repayment profile and secure funding for the Company's 2017 capital expenditure program. The significant financing transactions are as follows:

- Exchange of $17.4 million aggregate principal amount of its existing senior notes maturing in 2018 and 2019 for new 8.75% senior notes having an extended maturity date of January 23, 2022 (the "2022 Senior Notes"). The remaining $27.6 million senior notes maturing in 2018 were redeemed by cash repayment of $27.1 million and $0.5 million through an exchange for new 2022 Senior Notes (note 11);

- Establishment of the Term Loan with total availability of $45 million bearing annual interest at 8.1% and maturing March 14, 2021 (note 10). In addition, for no additional consideration, 5.4 million warrants were issued and valued at $0.8 million which entitle the lender to acquire common shares on a one for one basis for a period of up to three years, at an exercise price of $2.34 per share. The initial draw on the Term Loan was $35 million with the second and final draw of $10 million occurring on October 5, 2017;

- Issuance of 5.1 million common shares and 1.1 million additional warrants for aggregate gross proceeds of $9 million on March 14, 2017;

- Three borrowing base increases to the Company's reserve based, revolving bank debt (the "Credit Facility") comprised of a $14 million increase in March of 2017, a $20 million increase in July 2017 and a $25 million increase in November 2017 to a total borrowing limit of $65 million. Restricted cash of $2 million was released by the lender. The maturity date was extended to May 31, 2019 (note 9); and

- Establishment of a new $18.7 million TOU share margin loan secured by 1.67 million TOU shares maturing in July 2018. Proceeds from the new margin loan along with borrowings under the Credit Facility were used to repay the $36.5 million TOU share put option margin loans that were scheduled to mature in August and November of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options (note 8).

These financing transactions provide the Company with enhanced optionality and flexibility to manage near term obligations while at the same time, creating opportunities to continue pursuing exploration and development projects. 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.

## 8. TOU SHARE MARGIN LOAN

At December 31, 2017, Perpetual had an $18.4 million TOU share margin loan ($18.5 million principal amount) secured by 1.67 million TOU shares that matures on July 31, 2018 representing a 40% loan to TOU share value lending ratio at the date of funding. Interest rates are indexed to the same applicable Banker's Acceptance margins as the Credit Facility (note 9) ranging between 1.5% and 4.0%. 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 loan compared to the daily 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 loan to restore the lending ratio to 40%. As at December 31, 2017, the Lending Ratio was 48% of the closing market value of the pledged TOU shares. Subsequent to December 31, 2017, the TOU share price has declined in value, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the Lending Ratio at less than 55%, funded from borrowings on its Credit Facility. The TOU share margin loan is designated as a financial liability measured at amortized cost.

The effective interest rate on the TOU share margin loan as at December 31, 2017 was 4.0%. For the year ended December 31, 2017, if interest rates changed by 1%, with all other variables held constant, the annual impact on interest expense and net income (loss) would be $0.2 million.

Proceeds from this margin loan along with borrowings under its Credit Facility were used to repay the TOU share put option margin loans during the third quarter of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options.

Prior to repayment, the TOU share put option margin loans were hybrid financial instruments comprising a debt host with an embedded TOU share put option derivative related to indexation of the future settlement amount to changes in the market price of TOU shares pledged as collateral. The Company had designated the TOU share put option margin loans as financial liabilities which were measured at fair value through profit and loss. For the year ended December 31, 2017, a loss of $1.4 million (2016 - $6.5 million loss) is included in finance expense, representing the change in fair value of the TOU share put options during the year (note 17).

In addition to the Lending Ratio requirements, the TOU share margin loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin loan covenants at December 31, 2017.

## 9. REVOLVING BANK DEBT

As at December 31, 2017, the Company's reserve-based Credit Facility had a borrowing limit (the "Borrowing Limit") of $65.0 million (December 31, 2016 – $6.0 million) under which $31.6 million was drawn (December 31, 2016 – nil) and $3.9 million of letters of credit had been issued (December 31, 2016 – $4.0 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 2.0% and 4.5%.

The Credit Facility will continue to revolve until May 31, 2018 and may be extended for a further 364 day period subject to approval by the syndicate. If not extended, the Credit Facility will cease to revolve and all outstanding advances will be repayable on May 31, 2019. The next Borrowing Limit redetermination is scheduled on or prior to May 31, 2018.

Borrowings are secured by general security agreements covering all of the Company's assets with the exception of TOU shares that have been pledged as security for the TOU share margin loans (note 8) and certain lands pledged to the gas over bitumen royalty financing counterparty.

The effective interest rate on the Credit Facility at December 31, 2017 was 4.3%. For the years ended December 31, 2017 and 2016, if interest rates changed by 1% with all other variables held constant, the annual impact on interest expense and net income (loss) would be $0.3 million (2016 – $0.1 million).

Prior to the July 4, 2017 Borrowing Limit redetermination, the Credit Facility was subject to a working capital covenant which required the Company to maintain net working capital plus outstanding letters of credit not exceeding the Borrowing Limit. Net working capital includes the sum of cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and unpledged TOU shares less accounts payable and accrued liabilities and accrued interest on senior notes and the Term Loan up to the Credit Facility maturity date. On July 4, 2017, as part of the Borrowing Limit redetermination, Perpetual's lenders removed this working capital covenant. The Credit Facility also contains provisions which restrict the Company's ability to pay dividends on or repurchase its common shares.

At December 31, 2017, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

## 10. 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 (note 15c).

| | December 31, 2017 |
|---|---|
| Balance, beginning of year | $ – |
| Principal amount of Term Loan issued | 45,000 |
| Value allocated to Warrants issued | (769) |
| Issue costs | (1,361) |
| Amortization of issue costs | 363 |
| Balance, end of year | $ 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. The $45 million Term Loan consisted of an initial draw of $35 million completed upon closing with the final $10 million drawn on October 5, 2017. 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 (note 9). 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 loan lenders and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2017, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

## 11. SENIOR NOTES

| | | | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|---|---|
| | Maturity date | Interest rate | Principal | Carrying Amount | Principal | Carrying amount |
| 2018 Senior Notes | March 15, 2018 | 8.75% | $ – | $ – | $ 36,013 | $ 35,847 |
| 2019 Senior Notes | July 23, 2019 | 8.75% | 14,572 | 14,476 | 24,560 | 24,273 |
| 2022 Senior Notes | January 23, 2022 | 8.75%(1) | 17,918 | 17,204 | – | – |
| | | | $ 32,490 | $ 31,680 | $ 60,573 | $ 60,120 |

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

On January 23, 2017, the Company exchanged $8.4 million and $9.0 million aggregate principal amount of 2018 Senior Notes and 2019 Senior Notes respectively for $17.4 million new 8.75% senior notes with a maturity date of January 23, 2022 (collectively, the "Senior Notes"). Included in the exchange were $3.7 million 2018 Senior Notes and $4.3 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them. The 2022 Senior Notes bear a fixed rate of 9.75% for the first year of issuance and 8.75% thereafter, and have identical covenants and rights as the existing 2018 and 2019 Senior Notes.

On April 17, 2017, Perpetual redeemed $27.1 million aggregate outstanding principal amount of its 8.75% senior notes maturing March 15, 2018 for cash and exchanged the remaining $0.5 million for the issuance of an equal amount of 2022 Senior Notes. In mid-July, $1.0 million face value of 2019 Senior Notes were purchased at 96.75% of face value and retired.

During the second quarter of 2016, the Company repurchased and cancelled $114.0 million of outstanding 2018 Senior Notes and $100.4 million of outstanding 2019 Senior Notes through the exchange of 4.4 million TOU shares and cash payments of $3.9 million for accrued interest (the "Security Swap"). The fair market value of TOU shares exchanged was $130.5 million based on an average closing price of $29.64 per share. Included in the exchange were $81.6 million 2018 Senior Notes and $57.0 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them. The Company recorded a net gain on the Security Swap of $81.3 million, representing the difference between the carrying amount of senior notes cancelled of $212.0 million ($214.4 million principal amount) and the fair market value of TOU shares exchanged of $130.5 million, net of transaction costs.

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% 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% of the Senior Notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100% of the Senior Notes at the principal amount.

The Senior Notes have a cross-default provision with the Company's credit facility (note 9). 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, Term Loan, TOU share margin loans and gas over bitumen royalty financing) to trailing twelve months income before interest, taxes, depletion and depreciation and non-cash items ("TTM EBITDA") is less than 3.0 to 1.0 (the "Consolidated Debt Ratio"), the sum of 50% of TTM EBITDA from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100% of the fair market value of any equity contributions made to the Company during that period less the sum of all restricted payments during that period; and

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

At December 31, 2017 the Senior Notes are presented net of $0.8 million in issue costs which are amortized over the remaining term to maturity using a weighted average effective interest rate of 9.6%.

At December 31, 2017, in addition to 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.

## 12. GAS OVER BITUMEN ROYALTY FINANCING

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Balance, beginning of year | **$ 8,344** | $ 10,011 |
| Payments | **(2,421)** | (2,164) |
| Change in fair value | **(3,184)** | 497 |
| Balance, end of year | **$ 2,739** | $ 8,344 |
| | | |
| Gas over bitumen royalty financing – current | **$ 1,152** | $ 3,390 |
| Gas over bitumen royalty financing – non-current | **1,587** | 4,954 |
| | **$ 2,739** | $ 8,344 |

In 2014, the Company entered into an agreement whereby the Company received cash proceeds of $21.3 million in exchange for an obligation to make a monthly cash payment equivalent to a portion of the Company's monthly gas over bitumen royalty adjustment entitlements until final expiries in June 2021. Monthly payments under the arrangement are due on the 25th day following the entitlement month.

At the inception of the arrangement, the estimated future payments were determined using the same formula as the Company's monthly gas over bitumen royalty adjustment entitlements under the Alberta Natural Gas Royalty Regulation based on a January 1, 2014 forecast for the Alberta gas reference price ("base cash payment"). In the event that the actual Alberta gas reference price for a month causes the actual monthly cash payment under the arrangement to differ from the base cash payment, the Company is required to (a) pay 65 percent of any increase from the base cash payment, or (b) deduct 100 percent of any decrease from the base cash payment. Security for the gas over bitumen royalty financing is provided by an interest in certain lands of the Company and by the Company's entitlement to future gas over bitumen royalty adjustments.

The gas over bitumen royalty financing is a hybrid financial instrument comprised of a debt host with an embedded derivative related to indexation of the future cash payments to changes in the future Alberta gas reference price. The Company has designated the gas over bitumen royalty financing as a financial liability which is measured at fair value through profit and loss. For the year ended December 31, 2017, an unrealized gain of $3.2 million (December 31, 2016 – unrealized loss of $0.5 million) is included in finance expense related to the change in fair value of the gas over bitumen royalty financing.

As at December 31, 2017, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of the gas over bitumen royalty financing and after tax net income (loss) for the period would change by $0.6 million (December 31, 2016 - $0.9 million).

## 13. PROVISIONS

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Decommissioning obligations | **$ 37,081** | $ 33,620 |
| Restructuring costs | **1,604** | 4,154 |
| Total provisions | **$ 38,685** | $ 37,774 |
| | | |
| Provisions – current | **$ 2,580** | $ 7,656 |
| Provisions – non-current | **36,105** | 30,118 |
| | **$ 38,685** | $ 37,774 |

**a) Decommissioning obligations**

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Decommissioning obligations, beginning of year | **$ 33,620** | $ 159,169 |
| Obligations incurred | **1,554** | 177 |
| Obligations settled | **(2,336)** | (3,803) |
| Accretion (note 17) | **775** | 2,643 |
| Obligations disposed (note 5a) | **–** | (129,602) |
| Change in risk free interest rate | **2,339** | 10,184 |
| Change in estimates | **1,129** | (5,184) |
| Decommissioning obligations, end of year | **$ 37,081** | $ 33,620 |
| | | |
| Decommissioning obligations – current | **$ 2,243** | $ 4,012 |
| Decommissioning obligations – non-current | **34,838** | 29,608 |
| | **$ 37,081** | $ 33,620 |

Total future decommissioning obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods.

The Company adjusts the decommissioning obligations at each period end date for changes in the risk-free interest rate. Accretion is calculated on the adjusted balance after considering additions and dispositions to property, plant, and equipment. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future years.

The following significant assumptions were used to estimate the Company's decommissioning obligations:

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Undiscounted obligations | **$ 38,525** | $ 37,877 |
| Average risk-free rate | **2.3%** | 2.3% |
| Inflation rate | **2.0%** | 1.5% |
| Expected timing of settling obligations | **1 to 25 years** | 1 to 25 years |

**b) Restructuring costs**

| | **Employee downsizing costs** | **Onerous office lease contract** | **Lease inducement** | **Total** |
|---|---|---|---|---|
| Balance, beginning of year | $ – | $ – | $ – | $ – |
| Initial recognition | 2,926 | 2,712 | – | 5,638 |
| Payments | (1,320) | (164) | – | (1,484) |
| Balance, December 31, 2016 | 1,606 | 2,548 | – | 4,154 |
| Transferred | – | (1,764) | 1,764 | – |
| Payments | (1,606) | (650) | (294) | (2,550) |
| Balance, December 31, 2017 | – | 134 | $ 1,470 | $ 1,604 |
| | | | | |
| Restructuring costs – current | – | 134 | $ 203 | $ 337 |
| Restructuring costs – non-current | – | – | 1,267 | 1,267 |
| | $ – | $ 134 | $ 1,470 | $ 1,604 |

As a result of the Company's disposition of the Shallow Gas Properties on October 1, 2016 (note 5a), the Company's employee base and office space requirements were significantly reduced. Restructuring costs of $5.6 million were expensed, comprised of employee downsizing costs of $2.9 million and office lease obligations associated with surplus office space of $2.7 million. Payments made in 2017 with respect to restructuring costs were $2.6 million (2016 – $1.5 million).

At December 31, 2016, the unused corporate office space was recorded as an onerous contract as the unavoidable costs associated with the lease contract exceeded the expected economic benefits to be received.

On February 1, 2017, Perpetual entered into a new head office lease at its current location for a 98 month period expiring March 31, 2025. As consideration, the landlord agreed to release the Company from all remaining obligations under its existing lease with remaining term to March 31, 2018 and remaining payments of $1.8 million were deferred over the 98 month term of the new lease. This lease inducement is comprised of $1.8 million related to surplus office space which was recognized as an onerous contract provision in 2016. The lease inducement is being amortized on a straight-line basis over the 98 month term of the new head office lease.

## 14. COMMITMENTS

At December 31, 2017, the Company's contractual obligations over the next five years and thereafter are as follows:

| Contractual repayments of financial liabilities | 2018 | 2019 | 2020 | 2021 | 2022 and thereafter | Total |
|---|---|---|---|---|---|---|
| Accounts payable and accrued liabilities | 31,410 | – | – | – | – | 31,410 |
| Fair value of derivatives | 7,885 | – | – | – | – | 7,885 |
| TOU share margin loan – principal | 18,490 | – | – | – | – | 18,490 |
| Revolving bank debt – principal | – | 31,826 | – | – | – | 31,826 |
| Term loan – principal | – | – | – | 45,000 | – | 45,000 |
| Senior notes – principal | – | 14,572 | – | – | 17,918 | 32,490 |
| Gas over bitumen royalty financing | 1,152 | 939 | 391 | 257 | – | 2,739 |
| Pipeline transportation commitments | 4,193 | 3,730 | 2,343 | 1,022 | 1,022 | 12,310 |
| Office and other operating lease commitments | 1,371 | 1,065 | 1,098 | 1,159 | 3,815 | 8,508 |
| Total | 64,501 | 52,132 | 3,832 | 47,438 | 22,755 | 190,658 |

## 15. SHARE CAPITAL

| | **December 31, 2017** | | December 31, 2016 | |
|---|---|---|---|---|
| | **Shares** *(thousands)* | **Amount** *($thousands)* | Shares *(thousands)* | Amount *($thousands)* |
| Balance, beginning of year | **53,421** | **$ 1,325,705** | 19,068 | $ 1,296,734 |
| Issued pursuant to private place (c) and (e) | **5,143** | **8,968** | 491 | 839 |
| Issued pursuant to share based payment plans | **887** | **1,728** | 807 | 1,184 |
| Issue pursuant to share purchase rights (f) | **–** | **–** | 33,268 | 27,082 |
| Shares held in trust purchases (b) | **(708)** | **(1,000)** | (218) | (162) |
| Shares held in trust issued (b) | **520** | **1,437** | 5 | 28 |
| **Balance, end of year** | **59,263** | **$ 1,336,838** | 53,421 | $ 1,325,705 |

### a) Authorized

Authorized capital consists of an unlimited number of common shares. On March 24, 2016, shareholders of the Company approved the consolidation of common shares on the basis of 20 common shares to one common share, which has been retroactively applied throughout these consolidated financial statements.

### b) Shares held in trust

The Company has compensation agreements in place with employees whereby they may be entitled to receive shares of the Company purchased on the open market by a trustee (note 16d). Share capital is presented net of the number and cumulative purchase cost of shares held by the trustee that have not yet been issued to employees. As at December 31, 2017, 448 thousand shares were held in trust (December 31, 2016, 260 thousand).

### c) Warrants and equity private placement

On March 14, 2017, the Company completed a private placement of 5.1 million equity units for gross proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to warrants. Each equity unit consisted of 1 common share and 0.21 warrants resulting in the issuance of 5,143,000 shares and 1,080,000 warrants. Included in the issuance were 1.6 million common shares and 0.4 million warrants issued to directors and officers of the Company or entities controlled by them, for proceeds of $2.9 million. In addition, 5.4 million warrants valued at $0.8 million were issued in connection with the Term Loan (note 10). Each warrant entitles the holder to acquire common shares on a one for one basis at an exercise price of $2.34 per share prior to March 14, 2020.

The following table summarizes the warrants and common shares issued:

| | **December 31, 2017** | | | |
|---|---|---|---|---|
| | **Shares** (*thousands*) | **Amount** (*$thousands*) | **Warrants** (*thousands*) | **Amount** (*$thousands*) |
| Balance, beginning of year | – | $ – | – | $ – |
| Issue through Term Loan | – | – | 5,400 | 769 |
| Issued through private placement | 5,143 | 8,968 | 1,080 | 154 |
| **Balance, end of year** | **5,143** | **$ 8,968** | **6,480** | **$ 923** |

If the volume weighted average price of Perpetual's common shares is greater than $2.34 per share for 60 consecutive calendar days, Perpetual has the option to require warrant holders to exercise all or any portion of the warrants at any time thereafter.

### d) Per share information

| For the year ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| (*thousands, except per share amounts*) | | |
| Net income (loss) – basic | **$ (35,971)** | $ 107,149 |
| Effect of dilutive securities | **–** | – |
| Net income (loss) – diluted | **$ (35,971)** | $ 107,149 |
| | | |
| Weighted average shares | | |
| Common shares outstanding | **58,370** | 50,985 |
| Effect of shares held in trust | **(353)** | (252) |
| Weighted average common shares outstanding – basic | **58,017** | 50,733 |
| Effect of dilutive securities | **–** | 3,305 |
| Weighted average common shares outstanding – diluted | **58,017** | 54,038 |
| | | |
| Net income (loss) per share – basic | **$ (0.62)** | $ 2.11 |
| Net income (loss) per share – diluted | **$ (0.62)** | $ 1.98 |

In computing per share amounts for the year ended December 31, 2017, 15.7 million (December 31, 2016 – 1.5 million) potentially issuable common shares pursuant to Warrants and share based compensation plans were excluded because they were anti-dilutive.

### e) Flow-through shares

On November 17, 2016, the Company issued 0.5 million flow-through shares at a price of $2.15 per share for total gross cash proceeds of $1.1 million. The implied premium received in excess of the fair value of the common shares on the date of issue was $0.2 million or $0.44 per share and was recorded in accounts payable and accrued liabilities pending the incurrence of qualified exploration and development expenditures by the Company. As at December 31, 2016, the Company was committed to spend $1.1 million on qualified exploration expenditures by December 31, 2017. The expenditures have been incurred in 2017 and renounced to investors with an effective renunciation date of December 31, 2016.

### f) Share purchase rights

On December 7, 2015, the Company filed a short form prospectus with the security regulatory authorities in connection with a rights offering to issue common shares of the Company for gross proceeds of $25 million. The rights offering was fully backstopped by an entity controlled by the Chairmen of the Company's Board of Directors.

Pursuant to the rights offering, each registered holder of common shares as of December 16, 2015 received one right (a "Share Purchase Right") for each common share held. Each Share Purchase Right entitled the holder to acquire 0.2169 common shares upon payment of the exercise price of $3.26 per Share Purchase Right. The number of common shares received for each Share Purchase Right was calculated following the close of trading of the common shares on the Toronto Stock Exchange on December 22, 2015 based upon the volume weighted average price of the common shares for the preceding 20 consecutive trading days, being November 25, 2015 through to and including December 22, 2015.

For the year ended December 31, 2015, the Company recorded a gain of $7.5 million included in non-cash finance expense (note 18) related to the change in the carrying amount of the Share Purchase Rights derivative between filing of the prospectus on December 7, 2015 and determination of the number of common shares to be issued for each Share Purchase Right on December 22, 2015.

Upon closing of the rights offering on January 18, 2016, the Company issued an aggregate of 33.3 million common shares of the Company including 21.4 million issued to entities controlled by the Chairman of the Company's Board of Directors for proceeds of $16.1 million.

## 16. SHARE-BASED PAYMENTS

The components of share-based payments are as follows:

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Share options | **$ 997** | $ 883 |
| Restricted rights | **73** | 900 |
| Performance share rights | **937** | 480 |
| Compensation awards | **2,303** | 3,648 |
| Share-based payments | **$ 4,310** | $ 5,911 |

Concurrent with the share consolidation on March 24, 2016, the Company's board of directors approved modifications to existing share-based compensation agreements with directors, officers and employees of the Company resulting in an incremental expense of $2.0 million.

### a) Share option plan

Perpetual's share option plan provides a long-term incentive to employees and directors associated with the Company's long-term performance. The Board of Directors administers the share option plan and determines participants, number of share options and terms of vesting. The exercise price of the share options granted shall not be less than the value of the weighted average trading price for the Company's common shares for the five trading days immediately preceding the date of grant. Share options granted have a maximum term of 5 years and vest evenly on each anniversary date.

The following tables summarize information about share options outstanding:

| | **December 31, 2017** | | December 31, 2016 | |
|---|---|---|---|---|
| | **Average exercise price** *($/share)* | **Share options** *(thousands)* | Average exercise price *($/share)* | Share options *(thousands)* |
| Balance, beginning of year | **1.71** | **2,068** | 1.23 | 14,794 |
| Granted | **1.71** | **2,015** | 1.42 | 2,275 |
| Cancelled/forfeited | **–** | **–** | 1.69 | (682) |
| Expired | **3.23** | **(96)** | 3.41 | (386) |
| Modification | **–** | **–** | 1.11 | (13,933) |
| Balance, end of year | **1.67** | **3,987** | 1.71 | 2,068 |

| | **Options outstanding** | | | **Options exercisable** | |
|---|---|---|---|---|---|
| **Range of exercise prices** | **Number of share options** **(*thousands*)** | **Average contractual life** **(*years*)** | **Weighted average exercise price** **(*$/share*)** | **Number of share options** **(*thousands*)** | **Weighted average exercise price** **(*$/share*)** |
| $1.15 to $1.29 | 40 | 4.8 | 1.15 | – | – |
| $1.30 to $1.57 | 1,085 | 3.4 | 1.42 | 451 | 1.42 |
| $1.58 to $1.86 | 1,975 | 4.4 | 1.72 | – | – |
| $1.87 to $5.97 | 167 | 1.6 | 4.01 | 126 | 4.67 |
| Total | 3,987 | 3.8 | 1.67 | 577 | 2.13 |

The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding share options at the date of grant. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

| | **2017** | 2016 |
|---|---|---|
| Dividend yield (%) | **0.0** | 0.0 |
| Forfeiture rate (%) | **5.0** | 20.6 |
| Expected volatility (%) | **60.0** | 60.7 |
| Risk-free interest rate (%) | **0.8** | 0.5 |
| Expected life (years) | **3.2** | 3.2 |
| Vesting period (years) | **4.0** | 4.0 |
| Contractual life (years) | **5.0** | 5.0 |
| Weighted average grant date fair value | **$ 0.64** | $ 0.73 |

### b) Restricted rights plan

The Company has a restricted rights plan for certain officers, employees and consultants. Restricted rights granted under the restricted rights plan may be exercised during a period (the "Exercise Period") not exceeding five years from the date upon which the restricted rights were granted. The restricted rights typically vest on a graded basis over two years. At the expiration of the Exercise Period, any restricted rights which have not been exercised shall expire. Upon vesting, the plan participant is entitled to receive one common share for each right held at a cost of $0.01 per share.

The fair value of an award granted under the restricted rights plan is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date. This fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. Upon exercise of restricted rights, the value in contributed surplus pertaining to the exercise is recorded as shareholders capital. The estimated weighted average fair value of restricted rights granted during the year ended December 31, 2017 was $1.58 per award (2016 – $1.79).

Restricted rights granted upon the exercise of performance share units (note 16c) and deferred shares (note 16d) vest on the grant date and have a 30 day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense have been recognized pursuant to the grant date and expensed over the vesting period of the underlying performance share units and deferred shares.

The following table shows changes in the restricted rights outstanding under the restricted rights plan:

| (*thousands*) | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Balance, beginning of year | **273** | 40 |
| Granted to employees | **44** | 390 |
| Granted pursuant to exercise of performance share rights (c) | **209** | 143 |
| Granted pursuant to exercise of deferred shares (d) | **369** | 549 |
| Exercised | **(895)** | (811) |
| Modification | **–** | (38) |
| Balance, end of year | **–** | 273 |

### c) Performance share rights plan

The Company has a performance share rights plan for the Company's executive management team. Performance rights granted under the performance share rights plan vest two years after the date upon which the performance rights were granted. The performance rights that vest and become redeemable are a multiple of the performance rights granted dependent upon the achievement of certain performance metrics over the vesting period. Vested performance rights can be settled in cash or restricted rights (note 16b), at the discretion of the Board of

Directors. Should participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date, the performance rights would be forfeited.

The fair value of an award granted under the performance share rights plan is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. As at December 31, 2017, performance multipliers of 2.0 and 1.0 have been assumed for those unvested awards granted in 2016 and 2017 respectively. Fluctuations in share-based payments may occur due to changes in estimates of performance outcomes. The amount of share-based payment expense is reduced by an estimated forfeiture rate of 5% (2016 – 5%) for outstanding awards. The estimated weighted average fair value of performance share rights granted during the year ended December 31, 2017 was $1.68 per award (2016 – $1.40).

The following table shows changes in the performance share rights outstanding under the performance share rights plan:

| (*thousands*) | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Balance, beginning of year | **1,048** | 2,251 |
| Granted | **430** | 830 |
| Exercised in exchange for restricted rights[1] | **(418)** | (285) |
| Cancelled/forfeited | **–** | (1,193) |
| Modification | **–** | (555) |
| Balance, end of year | **1,060** | 1,048 |

[1] In 2017, performance share rights were exercised in exchange for restricted rights based on a performance multiplier of 0.5.

## d) Deferred compensation awards

### *Deferred options*

The Company has deferred option agreements in place with certain employees whereby over a period of three years they may be entitled to receive shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company during such time and exercise their options. The shares purchased by the independent trustee are reported as shares held in trust (note 15b).

The following tables summarize information about the deferred options:

| | **December 31, 2017** | | December 31, 2016 | |
|---|---|---|---|---|
| | **Average exercise price** (*$/share*) | **Deferred options** (*thousands*) | Average exercise price (*$/share*) | Deferred options (*thousands*) |
| Balance, beginning of year | **1.69** | **1,072** | 1.23 | 4,024 |
| Granted | **1.72** | **1,380** | 1.73 | 1,151 |
| Cancelled/forfeited | **1.74** | **(120)** | 1.28 | (354) |
| Expired | **2.55** | **(64)** | – | – |
| Modification | **–** | **–** | 1.28 | (3,749) |
| Balance, end of year | **1.68** | **2,268** | 1.69 | 1,072 |

| | **Deferred options outstanding** | | | **Deferred options exercisable** | |
|---|---|---|---|---|---|
| **Range of exercise prices** | **Number of deferred options** (*thousands*) | **Average contractual life** (*years*) | **Weighted average exercise price** (*$/share*) | **Number of deferred options** (*thousands*) | **Weighted average exercise price** (*$/share*) |
| $1.30 to $1.57 | 821 | 3.4 | 1.42 | 205 | 1.42 |
| $1.58 to $1.86 | 1,366 | 4.4 | 1.72 | – | – |
| $1.87 to $5.97 | 81 | 1.7 | 3.65 | 59 | 4.26 |
| Total | 2,268 | 3.9 | 1.68 | 264 | 2.05 |

The Company used the Black Scholes pricing model to calculate the estimated fair value of deferred options at the date of grant. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

| | **2017** | 2016 |
|---|---|---|
| Dividend yield (%) | **0.0** | 0.0 |
| Forfeiture rate (%) | **10.0** | 0.8 |
| Expected volatility (%) | **60.0** | 60.7 |
| Risk-free interest rate (%) | **0.7** | 0.5 |
| Expected life (years) | **2.2** | 2.1 |
| Vesting period (years) | **4.0** | 4.0 |
| Contractual life (years) | **5.0** | 5.0 |
| Weighted average grant date fair value | **$ 0.53** | $ 0.59 |

### *Deferred shares*

The Company also has deferred share agreements in place with directors and certain employees whereby, in the case of directors, upon retirement from the board of directors, or in the case of employees, over a period of two years if they remain employees of the Company during such time, may be entitled to receive at the discretion of the Board, cash, a grant of restricted rights (note 16b) or shares of the Company purchased on the open market by an independent trustee. The shares purchased by the independent trustee are reported as shares held in trust (note 15b).

The fair value of these agreements is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date and is reduced by an estimated forfeiture rate of 5% (2016 – 5%). The fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. Upon exercise of these agreements in exchange for restricted rights, the value in contributed surplus pertaining to the exercise is recorded as shareholders capital. Upon exercise of these agreements in exchange for shares held in trust, the shares held in trust account is reduced by the number of shares issued using the average cost base of purchased shares and offset to contributed surplus. The estimated weighted average fair value of these awards granted during the year ended December 31, 2017 was $1.60 per award (2016 – $1.62).

The following table shows changes to these awards:

| (*thousands*) | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Balance, beginning of year | **2,197** | 3,534 |
| Granted | **684** | 2,244 |
| Exercised in exchange for shares held in trust (note 15) | **(520)** | (5) |
| Exercised in exchange for restricted rights | **(369)** | (549) |
| Cancelled/forfeited | **(135)** | (979) |
| Modification | **–** | (2,048) |
| Balance, end of year | **1,857** | 2,197 |

## 17. FINANCE EXPENSE

The components of finance expense are as follows:

| | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Cash interest | | |
| Interest on revolving bank debt | **$ 1,078** | $ 2,749 |
| Interest on TOU share margin loans | **687** | – |
| Interest on term loan | **2,441** | – |
| Interest on senior notes | **3,798** | 11,942 |
| Total cash interest | **$ 8,004** | $ 14,691 |
| Non-cash finance expense | | |
| Amortization of debt issue costs | **620** | 509 |
| Accretion on decommissioning obligations (note 13a) | **775** | 2,643 |
| Change in fair value of gas over bitumen royalty financing (note 12) | **(3,184)** | 497 |
| Change in fair value of TOU share margin loans (note 8) | **1,377** | 6,507 |
| Total non-cash finance expense (recovery) | **$ (412)** | $ 10,156 |
| Finance expenses | **$ 7,592** | $ 24,847 |

## 18. CHANGES IN NON-CASH WORKING CAPITAL INFORMATION

| For the year ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Accounts receivable | **$ (2,596)** | $ 8,059 |
| Prepaid expenses and deposits | **53** | 2,151 |
| Accounts payable and accrued liabilities | **10,153** | (17,364) |
| Change in non-cash working capital | **$ 7,610** | $ (7,154) |

The change in non-cash working capital has been allocated to the following activities:

| For the year ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Operating | **$ (9,480)** | $ (4,910) |
| Financing | **(216)** | 216 |
| Investing | **17,306** | (2,460) |
| Change in non-cash working capital | **$ 7,610** | $ (7,154) |

## 19. FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

### a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners, oil and natural gas marketers and derivative contract counterparties.

Credit risk associated with cash and cash equivalents and restricted cash balances is managed by maintaining balances with financial institutions that have investment grade credit ratings.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following sales. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large, well established purchasers. The Company historically has not experienced any significant collection issues with its oil and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and oil and gas production; in addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners, however, the Company does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Company manages the credit exposure related to derivatives by engaging in risk management transactions with credit worthy counterparties, and periodically monitoring counterparty credit assessments.

The combined carrying amount of cash and cash equivalents, restricted cash, accounts receivable and fair value of derivative assets as at December 31, 2017 was $17.2 million (December 31, 2016 – $27.0 million), representing the Company's maximum credit exposure. The Company's credit provisions are represented by its allowance for doubtful accounts receivable as at December 31, 2017 of $1.1 million (December 31, 2016 – $0.8 million). The amount of the allowance was determined by assessing the probability of collection for each past due receivable. The total amount of accounts receivables 90 days past due amounted to $2.1 million as at December 31, 2017 (December 31, 2016 – $2.0 million).

### b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking harm to the Company's reputation.

The Company anticipates that cash flows including cash flow from operating activities, proceeds from potential future asset dispositions and future disposition of its TOU share investment, cash and cash equivalents, and access to credit facilities will provide the required funds to discharge the Company's obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the $25^{th}$ of each month.

The Company's minimum contractual obligations, excluding estimated interest payments, at December 31, 2017 are detailed in note 14.

### c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, TOU share price, commodity prices and interest rates will affect the Company's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and fixed-price physical delivery sales contracts to manage market risks related to commodity prices, foreign currency rates and TOU share investment prices. All such transactions are conducted in accordance with the Company's Risk Management Policy, which has been approved by the Board of Directors.

#### i) Commodity price risk

Commodity price risk is the risk that the fair value or future cash flow will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollar, but also by world economic events that dictate the levels of supply and demand.  The Company manages commodity price risk using various financial derivatives and fixed-price physical delivery sales contracts.

As at December 31, 2017, the Company has variable priced physical natural gas sales contracts based on future market prices. These contracts are not classified as non-financial derivatives since the settlement price corresponds directly with fluctuations in natural gas prices.

*Natural gas contracts*

At December 31, 2017 the Company entered into the following physical fixed natural gas sales arrangements at AECO:

| Term | Sold/bought | Volumes (*GJ/d*) | Average price (*$/GJ*) | Fair Value (*$ thousands*) |
|---|---|---|---|---|
| January 2017 – March 2018 | Sold | 12,500 | 2.94 | 1,209 |

At December 31, 2017 the Company had entered into the following basis differential contracts between AECO and NYMEX:

| Term | Sold/bought | Volumes (*MMBTU/d*) | AECO-NYMEX differential (*$USD/MMBTU*) | Fair Value (*$ thousands*) |
|---|---|---|---|---|
| April 2019 - October 2019 | Sold | 15,000 | (1.10) | 1,506 |

*Natural gas contracts - sensitivity analysis*

As at December 31, 2017, if future AECO natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of commodity price derivatives and after tax net income for the period would change by $0.6 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

*Oil contracts*

At December 31, 2017, the Company had entered into the following West Texas Intermediate ("WTI") costless collar oil sales arrangements which settle in $USD.

| Term | Volumes at WTI (*bbls/d*) | Floor price (*$USD/bbl*) | Ceiling price (*$USD/bbl*) | Fair Value (*$ thousands*) |
|---|---|---|---|---|
| January 2018 – December 2018 | 250 | 50.00 | 58.40 | (327) |
| January 2018 – December 2018 | 250 | 50.00 | 60.00 | (221) |

At December 31, 2017, the Company had entered into the following oil basis differential contracts between WTI and Western Canadian Select ("WCS") trading.

| Term | Volumes at WTI (*bbls/d*) | WTI-WCS differential (*$USD/bbl*) | Fair Value (*$ thousands*) |
|---|---|---|---|
| January 2018 – March 2018 | 500 | (13.65) | 444 |
| January 2018 – March 2018 | 250 | (23.85) | 33 |
| April 2018 – June 2018 | 500 | (14.45) | 227 |

*Oil contracts - sensitivity analysis*

As at December 31, 2017, if future WTI oil prices increased by $5.00 per boe with all other variables held constant, the fair value of commodity price derivatives and after tax net income for the period would decrease by $1.1 million. If future WTI oil prices decreased by $5.00 per boe with all other variables held constant, the fair value of commodity price derivatives and after tax net income for the period would increase $0.5 million. Fair value sensitivity was based on published forward WTI and WCS prices.

The following table is a summary of the fair value of the Company's financial contracts by type:

| As at | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Physical natural gas contracts | **$ 1,209** | $ 1,876 |
| Financial natural gas contracts | **1,506** | 4,606 |
| Financial oil contracts | **156** | (1,138) |
| Financial foreign exchange contracts | **–** | (5,022) |
| Fixed portion of retained shallow gas marketing arrangements[1] | **(929)** | (4,698) |
| Non-fixed portion of retained shallow gas marketing arrangements | **(6,736)** | 3,809 |
| **Fair value of derivatives** | **$ (4,794)** | $ (567) |
| | | |
| Derivative assets – current | **1,585** | 8,326 |
| Derivative assets – non-current | **1,506** | 2,351 |
| Derivative liabilities – current | **(7,885)** | (9,221) |
| Derivative liabilities – non-current | **–** | (2,023) |
| **Fair value of derivatives** | **$ (4,794)** | $ (567) |

(1) At December 31, 2017, the cost of the put option between the periods of January 1, 2018 and March 31, 2018 was fixed at $0.9 million which settles monthly over the remaining term and is recorded at amortized cost. During the year ended December 31, 2017, payments of $3.8 million (2016 - $0.4 million) were recorded as a reduction to this liability.

The following table details the Company's changes in fair value of commodity price derivatives:

| For the years ended | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Unrealized gain (loss) on financial oil contracts | **$ 1,294** | $ (3,144) |
| Unrealized gain (loss) on financial natural gas contracts | **(3,099)** | 6,430 |
| Unrealized gain (loss) on physical natural gas contracts | **(667)** | 2,007 |
| Unrealized gain (loss) on forward foreign exchange contracts | **5,022** | 8,047 |
| **Unrealized change in fair value of commodity price derivatives** | **2,550** | 13,340 |
| Realized gain (loss) on financial oil contracts | **(1,738)** | 1,036 |
| Realized gain (loss) on financial natural gas contracts | **9,221** | 6,224 |
| Realized loss on forward foreign exchange contracts | **(4,178)** | (2,559) |
| **Change in fair value of commodity price derivatives** | **$ 5,855** | $ 18,041 |

### ii) Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows of the Company will fluctuate as a result of changes in foreign exchange rates. The majority of the Company's oil and natural gas sales are denominated in Canadian dollars. As the demand for oil and natural gas is substantially driven by the demand in the United States, the Company's exposure to US dollar foreign exchange risk is indirectly driven by the price of oil and natural gas. From time to time, the Company also uses foreign exchange contracts to mitigate the effects of fluctuations in exchange rates on the Company's cash flows.

In 2017, the Company settled its foreign exchange contracts at a cost of $4.2 million and had no outstanding foreign exchange contracts as at December 31, 2017.

### iii) Interest rate risk

The Company's Credit Facility and TOU share margin loan bear floating rates of interest and as such are subject to interest rate risk. Increased future interest rates will decrease future cash flows and net income or loss, thereby potentially affecting the Company's Credit Facility and TOU share margin loan. The Company had no interest rate swap or financial contracts in place as at or during the year ended December 31, 2017 (December 31, 2016 – nil).

## d) Fair value of financial assets and liabilities

The Company's fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of cash and cash equivalents, restricted cash, accounts receivable, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. Revolving bank debt and the TOU share margin loan bears interest at a floating market rate and accordingly the fair market value approximates the carrying amount.

The fair value of the gas over bitumen royalty financing is estimated by discounting future cash payments based on the forecasted Alberta gas reference price (note 12) multiplied by the contracted deemed volume. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted Alberta gas reference prices, are used in determination of the carrying amount. The discount rate of 12.2% was determined on inception of the agreement based on the characteristics of the instrument. The forecasted Alberta gas reference prices for the remaining term are based on AECO forward market pricing with adjustments for historical differences between the Alberta reference price and market prices.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

| As at December 31, 2017 | Gross | Netting[(1)] | Carrying Amount | Fair value Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|---|
| **Financial assets** | | | | | | |
| Fair value through profit and loss | | | | | | |
| TOU share investment | 37,985 | – | 37,985 | 37,985 | – | – |
| Derivatives | 3,462 | (371) | 3,091 | – | 3,091 | – |
| **Financial liabilities** | | | | | | |
| Financial liabilities at amortized cost | | | | | | |
| TOU share margin loan | 18,406 | – | 18,406 | 18,490 | – | – |
| Revolving bank debt | 31,581 | – | 31,581 | 31,826 | – | – |
| Senior notes | 31,680 | – | 31,680 | – | 32,490 | – |
| Term Loan | 43,233 | – | 43,233 | – | – | 45,000 |
| Fair value through profit and loss | | | | | | |
| Derivatives | 8,256 | (371) | 7,885 | – | 7,885 | – |
| Gas over bitumen royalty financing | 2,739 | – | 2,739 | – | – | 2,739 |

(1) Derivative assets and liabilities presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

| As at December 31, 2016 | Gross | Netting[(1)] | Carrying Amount | Fair value Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|---|
| **Financial assets** | | | | | | |
| Fair value through profit and loss | | | | | | |
| TOU share investment | 66,343 | – | 66,343 | 66,343 | – | – |
| Derivatives | 14,685 | (4,008) | 10,677 | – | 10,677 | – |
| **Financial liabilities** | | | | | | |
| Financial liabilities at amortized cost | | | | | | |
| Senior notes | 60,120 | – | 60,120 | – | 59,664 | – |
| Fair value through profit and loss | | | | | | |
| Derivatives | 15,252 | (4,008) | 11,244 | – | 11,244 | – |
| TOU share margin loan | 39,953 | – | 39,953 | – | – | 39,953 |
| Gas over bitumen royalty financing | 8,344 | – | 8,344 | – | – | 8,344 |

(1) Derivative assets and liabilities presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

## 20. DEFERRED INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's income (loss) before income tax. This difference results from the following items:

| As at | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Net income (loss) before income tax | **$ (35,971)** | $ 107,149 |
| Combined federal and provincial tax rate | **27.0%** | 27.0% |
| Computed income tax expense (recovery) | **(9,712)** | 28,930 |
| Increase (decrease) in income taxes resulting from: | | |
| Non-deductible expenses | **1,163** | 1,596 |
| Non-taxable capital (gain) loss | **3,061** | (18,095) |
| Other | **(521)** | 682 |
| Change in unrecognized tax asset | **6,009** | (13,113) |
| **Deferred income taxes** | **$ –** | $ – |

The following table summarizes the deferred income tax liabilities of the Company and its subsidiaries, which are offset against certain deferred income tax assets:

| For the years ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Liability: | | |
| Senior Notes | **$ 218** | $ – |
| Term Loan | **477** | – |
| TOU share investment | **–** | 2,087 |
| Other | **846** | 3,264 |
| Total deferred income tax liabilities | **1,541** | 5,351 |
| Asset: | | |
| Decommissioning obligations | **$ (1,541)** | $ (5,351) |

The unused tax losses and deductible temporary differences included in the Company's unrecognized deferred income tax assets are as follows:

| For the years ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Non-capital losses | **$ 169,027** | $ 138,012 |
| Capital losses | **138,817** | 139,937 |
| Property, plant and equipment | **26,750** | 50,163 |
| Decommissioning obligations | **29,130** | 2,061 |
| Gas over bitumen royalty financing | **2,739** | 8,344 |
| TOU share investment | **9,506** | – |
| Other | **15,611** | 18,886 |
| | **$ 391,580** | $ 357,403 |

At December 31, 2017, the unused non-capital losses expire between 2024 and 2037, and unused capital losses have no expiry date. The deductible temporary differences do not expire under current tax legislation. The petroleum and natural gas properties and facilities owned by the Company and its subsidiaries have an approximate tax basis of $336 million (December 31, 2016 – $317 million) available for future use as deductions from taxable income.

Deferred income tax assets have not been recognized in respect of these unused tax losses and temporary differences because it is not probable that future taxable profit will be available against which the Company can utilize the benefits.

## 21. KEY MANAGEMENT PERSONNEL

The Company has defined key management personnel as executive officers, as well as the Board of Directors, as they have the collective authority and responsibility for planning, directing and controlling the activities of the Company. The following table outlines the total compensation expense for key management personnel:

| For the years ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Short-term compensation | **$ 2,015** | $ 2,637 |
| Share-based payments | **2,008** | 1,871 |
| | **$ 4,023** | $ 4,508 |

## 22. SUPPLEMENTAL DISCLOSURE

The Company's consolidated statements of income (loss) and comprehensive income (loss) are prepared primarily by nature of expense, except for employee compensation costs which are included in both production and operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in production and operating and general and administrative expenses in the consolidated statements of income (loss) and comprehensive income (loss).

| For the years ended | **December 31, 2017** | December 31, 2016 |
|---|---|---|
| Production and operating | **$ 1,945** | $ 4,986 |
| General and administrative | **9,414** | 12,425 |
| Share-based payments | **4,310** | 5,911 |
| Restructuring costs | **–** | 2,926 |
| | **$ 15,669** | $ 26,248 |

# CORPORATE INFORMATION

## DIRECTORS

**Clayton H. Riddell**
Executive Chairman
**Susan L. Riddell Rose**
President, Chief Executive Officer and Director
**Robert A. Maitland**
Independent Director(1)(2)(3)
**Geoffrey C. Merritt**
Independent Director(1)(2)(4)
**Donald J. Nelson**
Independent Director(2)(4)
**Ryan A. Shay**
Independent Director(1)(3)
**Howard R. Ward**
Independent Director(3)(4)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Compensation and Corporate Governance Committee
(4) Member of Environmental, Health & Safety Committee

## OFFICERS

**Susan L. Riddell Rose**
President, Chief Executive Officer and Director
**W. Mark Schweitzer**
Vice President, Finance and Chief Financial Officer
**Jeffrey R. Green**
Vice President, Corporate and Engineering Services
**Linda L. McKean**
Vice President, Production and Development
**Marcello M. Rapini**
Vice President, Marketing

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## AUDITORS

KPMG LLP

## BANKERS

Alberta Treasury Branches
Bank of Montreal
Bank of Nova Scotia

## RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

## REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company

PERPETUAL ENERGY

STOCK EXCHANGE LISTING | TSX | **PMT**


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